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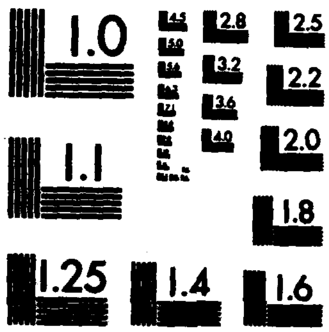
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ABSTRACT

This thesis discusses impacts and issues brought about by the enactment of the Public Utilities Regulatory Policies Act of 1978. The United States power grid has a history of safe, economical, reliable service that, some feel, is threatened by the encroachment of small Dispersed Energy Sources, with possible inexperienced developers. The quality of electrical power from such sources is in question, as is power grid stability and reliability. Safety is another factor where methodry is subject to the incentives of the party whose viewpoint is sought.

Much controversy is caused by the Act leaving methods of implementation to the individual States. The settlement, in one State, of some question in dispute forms no basis for extrapolation into other States. This leaves a potential developer with some uncertainty as to his options and advantages in assessing the incentives for investing in a Dispersed Energy Source. And such incentives form the thrust of the Act.

This thesis brings these issues to the fore and examines them for significance and possible resolution. It evaluates the outlook of the Utility, the Dispersed Energy Source, and the Public for motivation and attempts to strike a balance between their opinions in reaching conclusions. "Gray" areas are addressed and possible remedies are offered.

THE UNIVERSITY OF OKLAHOMA

GRADUATE COLLEGE

DISTRIBUTION SYSTEM STABILITY, RELIABILITY AND PROTECTIVE RELAYING DUE TO INCORPORATION OF DISPERSED ENERGY SOURCES

A THESIS

SUBMITTED TO THE GRADUATE FACULTY

in partial fulfillment of the requirements for the

degree of

MASTER OF SCIENCE

(ELECTRICAL ENGINEERING)

By

KENNETH LAURENCE ALLISON

Norman, Oklahoma

1984

DISTRIBUTION SYSTEM STABILITY, RELIABILITY AND PROTECTIVE RELAYING DUE TO INCORPORATION OF DISPERSED ENERGY SOURCES

A THESIS

APPROVED FOR THE SCHOOL OF ELECTRICAL ENGINEERING AND COMPUTER SCIENCE

By

Marvin E Council

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The support of both these gentlement made the thesis possible.

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CHAPTER I

INTRODUCTION

Section 1

It is well-known that the United States has become virtually a single electrical power grid, webbed by lines of moving electrons channeled at the whim of man to any point in the nation where that electricity is needed. This web allows the United States to possess the most reliable, economical power system of any nation in the world. It has been designed to allow for failures in the generation and distribution systems, for variety in consumption quantity, for natural destruction (lightning, landslides, floods), for ease of maintenance and for safety. It has built-in redundancy, multiple-supply feeders, interlock and bypass capability, and its operation is generally monitored by both humans and computers.

It should not fail. Providing multiple supplies of power generation to a grid should insure that the failure of a generator or component is compensated for by alternative equipment. The process should be automatic, with mere flickering of lights to mark the transition between a failed source and an alternate.

On November 9, 1965, a relay failed in a power station at

Niagara Falls. The resulting events caused electrical power to fail in most of the northeastern United States and in parts of Canada. It cost an estimated $350 million.[1] There is no estimate of the personal injury associated with the blackout.

How did this catastrophe occur? What motivated us to design a system that had the potential for withholding electrical power from 17% of our citizens and 22% of our heavy industry? Have there been changes to the system design which will prevent a recurrence? What recent factors may perturb these considerations?

Section 2

In the last twenty years of the nineteenth century, generators began springing up alongside streams and rivers throughout the United States. Those towns and businesses that could afford a generator and were located close enough to flowing water could obtain cheap, reasonably reliable electrical power initially used primarily for lighting. Further, sawmills and gristmills could locate conveniently close to a generator and power their equipment electrically. The reliability of the equipment was not great, and distribution systems were in their infancy, but these new systems represented a quantum jump forward in industrial operations.

It was realized in the early stages that the ability to "parallel" these systems greatly increased reliability. With several systems electrically connected, a failure in one could

be absorbed by increasing the output of the others. Also, maintenance could be scheduled at convenient times and actual power planning could begin. So geographically proximate communities and industries began to interconnect. At the turn of the century, industrial cogeneration accounted for more than 50% of the nation's power.[2]

Starting as a convenience, electricity rapidly became a driving necessity to the country's day-to-day operation. Water was the most economical source of power for generators although steam engines also made a solid beginning as prime movers, particularly in those areas not convenient to flowing water. Government projects in the 1930s included huge hydroelectric efforts capable of generating thousands of megawatts. Power lines were installed to transmit the electricity hundreds of miles from these giant dam sites to the metropolitan areas where the electricity was needed. Communities adjacent to the lines found that this power was much cheaper than their own and either interconnected or replaced their equipment with radial feeders off these lines. By 1950, industrial cogeneration was down to 15% of the nation's power and giant power grids were being established throughout the country.

It may be seen that it was during this period that a major transition in power policy took place. For although the power supplied to consumers became much more reliable, failures in the system began to have much further-reaching consequences. A component failure or shutdown in Washington state could affect

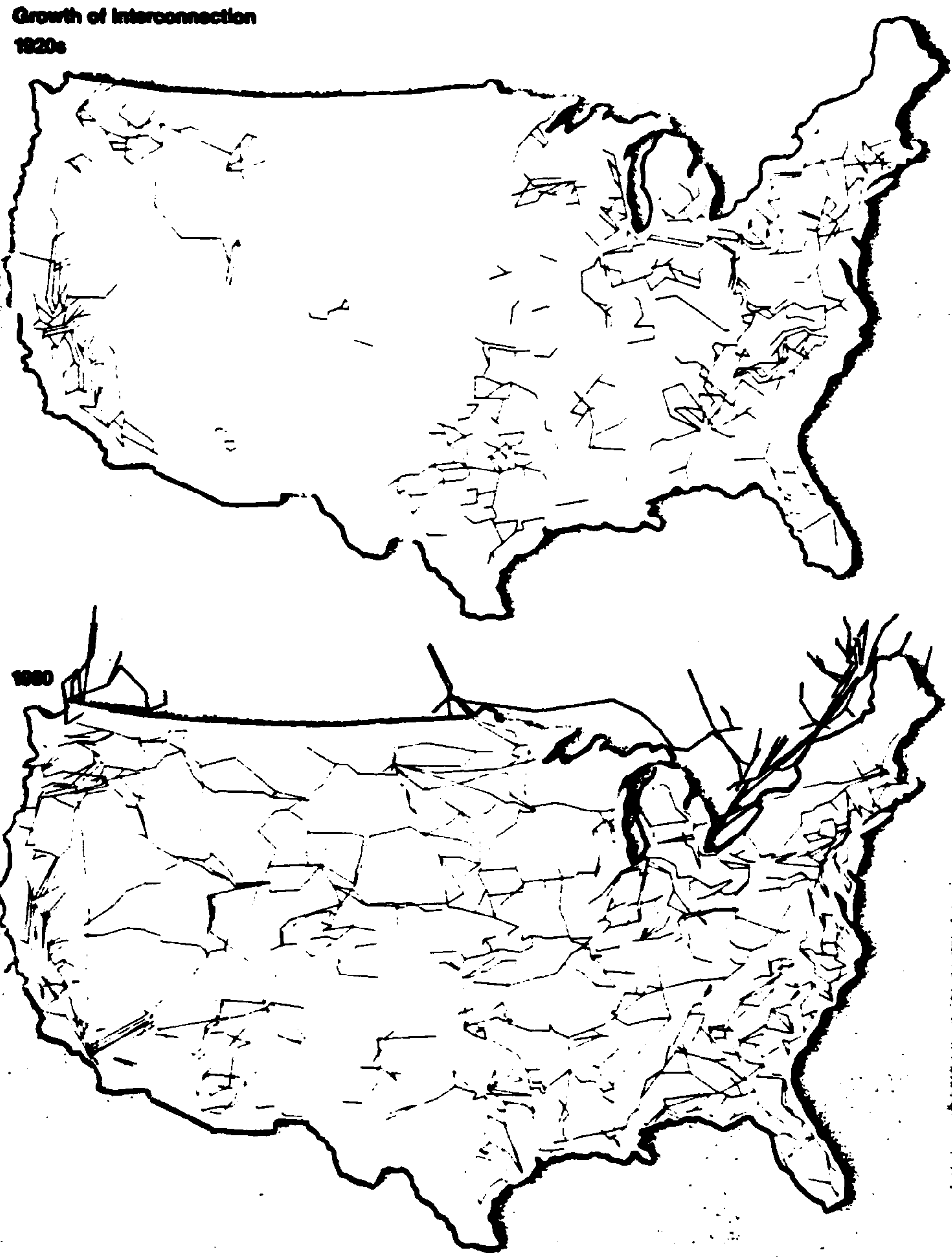
Washington, Utah, Idaho, Oregon and California.

Because of the size being reached by both public and private power generation facilities, operating practices had to be controlled, and government regulatory agencies were established for that purpose. Power suppliers who used public lands or transmission lines to sell power became "public utilities" and fell under these regulations.

In 1945, hydropower represented about 35% of the nation's supply of electricity. As fuels (natural gas, coal and oil) became cheaper and new dam sites became harder to locate, hydropower began a gradual decline. The eventual development of nuclear power sources further reduced the relative consumption of hydropower, as did the trend toward centralized generation and a national power grid. Cogeneration by industry also fell in relative prominence for economic reasons, and by 1981 accounted for less than 5% of the nation's power.[3]

It is easily seen that the advantages of a large power grid more than justify its creation. Multiple generating sources yield the redundancy to compensate for a failed source; down-time for equipment servicing and maintenance is simpler to schedule; long-range planning for equipment acquisition is possible; peak-load or unscheduled demands are more easily met; disruption due to natural destruction is minimized, and; impacts due to local growth spurts may be absorbed.

Our movement toward a national power grid is shown in Figure 1. The change from an independent power system posture in the



In the mid 1920s there was no interconnection of bulk transmission lines, and for all practical purposes, utilities were electrically isolated companies. Interconnection began on a large scale in the 1950s as a means of enhancing system reliability and sharing remotely generated power. This pooling arrangement has continued to grow in the last three decades, greatly increasing the complexity of power networks. It now requires hours of computer time to assess the state of dynamic stability within these systems.

Figure 1: Growth of Interconnection

Source: EPRI Journal, November 1982.

1920s to virtually one giant power system in 1980 is obvious. Only Texas remains uncommitted.

Section 3

The United States is energy hungry. Fossil fuels are becoming harder to obtain and more expensive, nuclear power has become extremely controversial, the best dam-sites are already in use, and other sources of power (wind, solar, waste) are largely undeveloped. While consumption is steadily increasing, new sources are becoming harder to locate.

In 1978, Congress passed Public Law 95-617. The Public Utility Regulatory Policy Act (PURPA) is a part of this law*. The purpose of PURPA is to encourage development of renewable resources as fuels for power generation and, further, to encourage private acquisition and installation of generating equipment using those resources to produce power. The Act attempts to do this by minimizing institutional barriers (licensing, inspection, regulation) for those falling within its perview, by requiring public utilities to purchase, at a reasonable rate, any excess power produced by these private generating facilities, and by paying part of the investment cost, via tax incentives, associated with these endeavors. Chapter II of this paper addresses PURPA in detail.

There are many types of generating facilities which fall under PURPA. Primarily, the Act is concerned with ensuring that whatever source causes the motion of the prime mover of the

*A list of acronyms and abbreviations is contained in Appendix A

generator is either already irretrievably lost (such as the waste heat in industrial processes) or continuously renewable (wind). Examples of such fuel include: Municipal waste, low-head hydropower, fuel cells, solar cells, wind, land-fills (methane), and waste heat. Chapter III in this thesis elaborates on these resources and discusses the advantages and disadvantages of each.

The requirement that public utilities interconnect with any qualifying producer of electricity has generated a number of concerns associated with implementation. Among the most important concerns are those having to do with protecting facilities and equipment from damage and people from injury in the event of a perturbation on the system. Current methods for accomplishing this are based on existing system design and will not work for dispersed energy sources. Many portions of our national grid include radial feeders, for example, which incorporate protective devices which will, in the event of a fault, only remove power from "upstream." For some consumers, little or no protection will be provided by the public utility to handle malfunctions or faults in a cogeneration facility. That responsibility will rest with the PURPA-qualifying producer. The types of protective devices currently used and criteria applied in coordinating them are discussed in Chapter IV.

It has already been mentioned that possessing a large power grid such as that in the United States insures a very high degree of reliability. But a sub-area of reliability that can be criti-

cally affected by a grid of this sort is stability. Stability is that characteristic of an electrical system, which, after a sudden fault, allows it to rebound into a new, stable, operating configuration. A close-coupled, peak-loaded system has little stability. A small fault can cause a disproportionate amount of damage. And many utility systems in the United States today are being forced to operate, during peak loads, in such a configuration. For this reason, added factors in the equation by which they operate are unwelcome. Utilities like to have a 10-20% spinning reserve available at all times and recent peak loads have shaved deeply into that reserve. Operating close to the system limit means that small failures may cascade into a general system shutdown. And some utilities view cogenerating facilities of up to 80 megawatts as having the potential of providing such a shutdown. An example is again provided by the New York power failure of 1965. The sequence of events was determined to be as follows:[1]

The associated power grid, at that time, stretched through most of the northeastern United States and adjacent parts of Canada. A single overcurrent relay in a power station at Niagara Falls was set to recognize a fault (short circuit) by a certain magnitude of current passing through it. Values above that level were to be interpreted as a short circuit somewhere downstream. Abnormally high consumer demand had occurred all afternoon, and at about 5:15 PM the preset value was reached. Erroneously interpreted as a fault, the current caused the relay to open the

circuit breaker. This particular relay was in one of five main lines heading north into Canada. When it dropped out, the other four lines overloaded and, one by one, they dropped out.

In a power generation system, all the generators must run at the same frequency; in this case, 60 cycles per second. But a characteristic of a generator is that when it is running at speed under full load, and that load suddenly drops off, the generator tries to accelerate. Other generators attempt, electrically, to hold the runaway generator in check, but, if they fail, protective relays and circuit breakers must be provided to remove the accelerating generator from the line.

When the five main lines into Canada dropped their load, various generators throughout the northeastern grid began to overspeed and automatic circuit breakers removed them from the grid. As the system began to settle, it was several generators short of what it had been. Because it had already been operating near its peak capacity, it now was in systemic trouble. The automatic relays into Canada reclosed (as they are designed to do) and completely overloaded the system. Other lines into the New England area had their relays open as the system attempted to correct itself. This only began the cycle anew and eventually caused the system to cascade into a complete shutdown. Service was not totally restored for several days, and, as already stated, the estimated cost was $350 million.

The relay previously discussed initiated the failure. But the lack of stability of the system itself carried the failure

through to inordinate system deterioration. The ability of a system to reconfigure itself (as must be done automatically because these events occur much too rapidly for humans to interfere) after a fault, to re-route electrical power, to remove failed equipment from the grid, to protect other equipment from damage, and to operate effectively in its new configuration are all measures of its STABILITY. Stability and reliability will be discussed in Chapter V as they are affected by PURPA.

The impact of PURPA on current production-facility and distribution-system design is many-faceted. The Act defines these small power producers as having the ability to generate up to 80 megawatts of power, not an insignificant amount. Circuit-protection devices, line capacities, impacts on other customers, interface methods, and cogeneration power quality and equipment standards are all considerations in implementing this Act.

Some of these concerns were addressed, to varying degrees of depth, during PURPA research and at the FERC hearings. Others have been reviewed in public-utility-sponsored studies. But a great deal of work remains to be done, in all areas, before a cogeneration facility producing 80 megawatts can confidently dump it in most places on the radial portions of the national grid. Many of these concerns will be discussed in Chapter VI.

The advent of computers brought about new capabilities for use in the design and installation of electrical power systems. Prior to that time, network analyzers were the most common tool

of the engineer. The tedious calculations necessary in the determination of just what electrical currents would flow in the event of a fault dictated that only a gross fault, normally all three phases of a power system shorted together and to ground, was evaluated. System components, conductors and protective devices were then incorporated using the three-phase fault data as baseline.

In reality, three-phase faults to ground seldom occur. The most typical fault is phase-to-ground, with phase-to-phase coming in a distant second. Computers have removed most of the drudgery from calculations of fault currents and allow us to more easily evaluate these two types of fault as well as the more traditional three-phase to ground. Various off-the-shelf computer programs are now available which compute fault currents in fractions of a second for both real and hypothetical transmission and distribution systems.

Once fault profiles are determined, and their respective fault currents established, methods of protecting the system from the results of such faults may be specified. The techniques used to determine optimum locations for protective devices, allowing them to protect the system with the least amount of power disruption to consumers, is called OVERCURRENT COORDINATION. Fault analysis techniques and overcurrent coordination are discussed in Chapter VII, along with their application to PURPA-perturbed power supply systems.

This thesis is not intended to provide solutions for all the

concerns pertaining to the implementation of PURPA. It is intended to bring the more technical aspects of those issues to the fore where they may be examined for possible significance. Key issues are prioritized, and conclusions and solutions are offered, in Chapter VIII. These conclusions and solutions are not, however, unique. The side issues attached to each particular concern permit many permutations of a conclusion, depending on the significance given each side issue. An example of this would be in how much priority one gave 'Environmental Impact" in routing transmission lines through the mountains. The location of a dam, the length of the line, the number of components, and the reliability may all be affected, not by engineering considerations, but by Environmental Impact. Though this side issue is certainly justifiable, it leaves an engineer with a good deal of uncertainty when he is evaluating the relative merits of a PURPA-inspired cogeneration facility.

Another problem one encounters in attempting to reach engineering conclusions on the ramifications of a public law is that reference data is infinite. One source will be 'pro' and will have a thousand good reasons why this is the only logical position to take. Another source will be 'con' and will also have a thousand good reasons. Sometimes, they are the same reasons, interpreted differently. There were, however, nuggets among the pebbles, and it is upon these nuggets that the conclusions of Chapter VIII are based.

CHAPTER II

Requirements of the PUBLIC UTILITY REGULATORY POLICIES ACT

General discussion

In 1977 and 1978, while Congress was considering the National Energy Act, a good deal of interest developed in three separate concepts concerning electrical power generation. The first concept dealt with the possible advantages of dispersed (or decentralized) energy sources (DES). The second dealt with possible methods for encouraging the development of small scale power generation facilities, preferably using renewable resources as fuels. The third concept addressed methods for encouraging development of cogeneration as an adjunct to other industrial processes.

Public Law 95-617 resulted from these considerations. It was enacted on November 9, 1978 as the Public Utility Regulatory Policies Act (PURPA). In general, certain sections of the Act directed that study groups be formed and that public hearings be held to evaluate proposed methods for encouraging the production of electricity while emphasizing the use of renewable resources as fuel sources. The pertinent sections of PURPA for the pur-

poses of this Thesis are sections 201 and 210. PURPA, overall, is a complex law having specific application to electric utilities'rate and service policies and deals only with very large systems. Sections 201 and 210, however, deal with the utilities' relationships to cogenerators and small power producers, thus addressing all sizes of power production facilities.[4]

After the required hearings, PURPA Section 210 was implemented by the Federal Energy Regulatory Commission (FERC) on February 25, 1980 by their order Number 69. Section 201 was implemented March 20, 1980 by order Number 70.

Section 201 establishes the qualifying criteria for small power production facilities and for cogeneration facilities. Its rules are directed at the non-utility groups who propose to build cogeneration or small power production facilities that qualify under PURPA. For many proposed facilities, the certification that they do, in fact, qualify, carries with it important economic incentives, some of which may play a major role in forming the decisions inherent in such an undertaking.

Section 210 establishes the guidelines under which a public utility is required to purchase power from those producers who qualify under Section 201. It provides guidance for establishing appropriate buy-back rates for the utility, requires that the utility furnish power, on request, to the Qualified Facility (QF), and requires that the utility provide, to the QF, cost data on its system upon which buy-back rates may be determined.

PURPA leaves it to the individual states to determine what

technical considerations arise from this Act. Such considerations as stability and reliability, interconnect methods, equipment specifications, safety and power quality are prerogatives of the state. It gave the states one year (until March, 1981) to be prepared to implement the Act.

The Act

Qualifying Facilities under PURPA fall into three categories. The first is that of the small power producer of 30 megawatts or less. The second is that of the small power producer of up to 80 megawatts who uses renewable resources as the fuel for more than 50% of his total energy input in generating that power. The third category is that of a cogenerating facility of 80 megawatts or less. Public utilities are not allowed ownership of, nor control over, these facilities.

A cogenerating facility is defined under PURPA as one which produces electricity and some other form of energy (such as heat) simultaneously. The law is designed to encourage the development of piggy-back generating equipment to take advantage of waste energy from already existing industrial processes. As stated in PURPA, "Cogeneration facilities can use significantly less fuel to produce electricity and steam (or other forms of energy) than would be needed to produce the two separately."[5]

PURPA notes that prior to its enactment, a cogenerator or small power producer seeking to establish interconnected operation with a utility faced three major obstacles. First, a

utility was not generally willing to purchase the electric output or was not willing to pay an appropriate rate. Secondly, some utilities charged discriminatorily high rates for back-up service to cogenerators and small power producers. Thirdly, a cogenerator or small power producer who provided electricity to a utility's grid ran the risk of being considered an electric utility and thus being subjected to extensive State and Federal regulation. Sections 201 and 210 of PURPA are designed to remove all three of these obstacles.

As a result of PURPA, qualifying facilities were exempted from the requirements of the Public Utility Holding Company Act of 1935, from most provisions of the Federal Power Act, and from State laws regulating electric utility rates and financial organization.

Following is a list of energy sources which may be used as fuels for the generation of electricity, or as sources of electricity themselves, for the purposes of the PURPA 'Renewable Resource' clause:[6]

1. Solar Energy
2. Geothermal Energy
3. Small-Scale Hydropower
4. Municipal Waste
5. Biomass
6. Wind
7. Other sources which are either irretrievably lost (waste heat) or constantly renewable (wood products)

PURPA Section 210. (a)(1) provides the authority for requiring utilities to interconnect with qualified facilities, while Section 212.(a) notes that no such requirement will exist unless it is "not likely to result in a reasonably ascertainable uncompensated economic loss of any electric utility, qualifying cogenerator, or qualifying small power producer." Section 212 further invalidates the requirement if it places an undue burden on any of the principals; if it might unreasonably impair the reliability of its subject electrical utility; or if it would impair the ability of its subject utility to render adequate service to its customers.

Section 292.306(a) of the FERC order addresses the responsibility for interconnection costs. It states, in general, that the utility may provide necessary interconnection equipment and charge the qualified facility reasonable interconnection costs. These costs are subject to review for fairness, but in all cases are the responsibility of the qualified facility.

Section 210 of PURPA also establishes methods by which utilities are required to purchase power and determine buy-back rates. Electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, in the public interest, and which do not discriminate against cogenerators or small power producers. The actual rates are to be determined by the cost that the utility can avoid as a result of purchasing power from these qualifying facilities.

In interpreting this legislation, the Federal Energy

Regulatory Commission ruled that rates paid to qualifying facilities would comply with PURPA if they were set equal to the costs the utility avoids by not having to supply the electricity from its own generating facilities or by purchasing it from another supplier. This defines "avoided costs."

The FERC regulations on Section 210 of PURPA required State public utility commissions (PUCs) to begin implementation of the regulations by March 1981. Since that time, a wide range of draft and final rules have been issued by the States, and utilities have published a variety of tariffs for cogenerated power or that from small power producers. The State PUCs have taken full advantage of the procedural latitude allowed by the FERC rules, using rulemaking, adjudication, and dispute resolution to establish the basis for determining fair rates. Appendix B illustrates some of the resulting rates on a state-by-state basis.

Section 210(a) of PURPA states that the rules requiring electric utilities to purchase power from qualifying facilities shall include provisions respecting minimum reliability requirements of such power. Section 292.308 of FERC Order Number 69 implements that legislation. It states, in part, that "The Commission has determined that safety equipment exists which can ensure that qualifying facilities do not energize utility lines during utility outages." Accordingly, Section 292 provides that "each State regulatory authority or nonregulated electric utility may establish standards for interconnected operation

between electric utilities and qualifying facilities." This passage, in effect, leaves it to the individual States to establish interconnect methods, safety devices, maintenance procedures and quality control techniques for use in implementing PURPA.

PURPA was conceived during the oil shortages of the mid-70s. It was one of a multitude of laws designed to develop new energy sources, decrease the demand for petroleum products, and increase the efficiency of petroleum-using machinery. The Congress utilized whatever tools were at its disposal in the promotion of operations under these new laws. Among the tools were tax incentives, market guarantees, red tape removal and the requirement for State cooperation. Congress' goal was to achieve a badly needed increase in United States petroleum independence.

Although PURPA was chief among the remedial legislation, other laws had major impacts on cogeneration and small power production. And although no comprehensive list of the laws applying to all types of cogeneration and small power production exists, following are examples of some Federal laws which do have an impact:

* **Energy Security Act of 1980**: Gave FERC the authority to exempt Small Scale Hydro projects (5MW or less of installed capacity) from the licensing process under the same restrictions as the conduit power restrictions in PURPA. Amended the PURPA "15MW or less definition" of Small Scale Hydro to "no more that 30 MW," and the definition of existing dams to include "any project which utilizes or proposes to utilize natural water features for the generation of electricity," thus opening the door for low-head hydro or run-of-river projects.

* **Economic Recovery Tax Act of 1981**: Established a "safe-harbor" for specified energy property as long as the Environmental Impact Commission is in effect and changed depreciation schedules for capital investments in equipment and structures to allow an accelerated cost recovery system based on either 5 or 15 years.

* **Tax Equity and Fiscal Responsibility Act of 1982**: Requires that the tax credits and accelerated cost recovery systems be considered together to prevent unwarranted subsidies and eliminates "safe-harbor" lease on December 31, 1983, replacing it with a new vehicle called the "finance lease." The Congress has before it several bills to drastically alter the terms of these benefits, stemming from the concern that they have provided enormous breaks on financing without the additional or complementary benefit of increased productivity of capital.

* **Crude Oil Windfall Profits Tax Act**: Among many other things, made Qualified Facilities eligible for the Alternative Energy Investment Credit, as an 11% tax credit for property used in the generation of electricity from hydropower with installed capacity of 125 MW or less. The amount of qualified investment, under this act, was reduced by 1% per megawatt (of the shelter) beginning at 25 megawatts. The Act also allows public bodies financing "qualified hydroelectric generating facilities" to use tax exempt industrial development bonds.

The States have followed suit in passing legislation to promote the development of cogeneration and small power production facilities. The result is that electric utilities nationwide now face modifications to their transmission and distribution systems in order to accomodate these requirements. Impacts will range from none at all in many geographical areas to significant modifications in others. Ultimately, however, power system designers will need to develop a safe, economical, reliable method for incorporating potential new sources into the national grid.

CHAPTER III

DISPERSED ENERGY SOURCE TYPES

General Discussion

Of the several types of Dispersed Energy Sources (DES), Cogeneration has the potential for being the most lucrative. It utilizes the residual effects of fuel which has already been used for some other purpose to power its generating equipment. After initial costs, investment would be slight. Ideally, there would be no fuel costs. This, as recognized by PURPA, is not really the case. There may actually be additional fuel required for start-up, excitation, or even to augment the primary energy source. Even so, fuel costs should be extremely low.

On the other hand, Small Power Production facilities also have many advantages. PURPA, in creating a guaranteed market, allowing tax shelters and removing bureaucratic requirements, has caused a great deal of re-evaluation of potentially profitable operations based strictly on state-of-the-art economics. Dams with previously closed hydroelectric operations have been restarted as being economically feasible. Trash disposal areas are being developed as sources of methane. Huge "wind farms," with row after row of wind-powered turbine generators, have

sprung up on the plains of the United States. Solar heating and photo-voltaic devices adorn new homes and factories.

This Chapter discusses the types of cogeneration and small power production facilities which fall under PURPA, along with some of the advantages and disadvantages of each. It must be borne in mind that these electrical power sources comprise a portion of a new, and very dynamic, system which will impinge upon the national grid. It is this new system for which transmission and distribution systems must be adapted in the coming decades, for which standards must be established, and which must be adjusted to conform to requirements for a reliable, stable power grid.

Cogeneration Facilities

In 1977, approximately 29% of the United States' energy consumption was used by the industrial sector. Of this, almost a quarter, or 6.5% of the nation's total purchased energy, was discharged as waste heat to the environment by the eight most energy intensive industries. Approximately 4% was discharged as flue gases, and 2% was discharged as identified waste-water and cooling water discharges. Within the overall industrial sector, approximately 37% of fuel consumption was discharged as waste heat by all major energy intensive industries. Flue gases accounted for about 23%, and identified wastewaters and cooling waters accounted for the other 14 percent[7]. Petroleum Refining discharged the largest quantity of flue gas waste heat to the

environment, with Steel Mills being second. These two industries together represented approximately 50% of the total annual flue gas waste heat discharged by the nineteen groups included in the referenced study (Latour 1982).

The cited statistics may be misleading because they represent **all** the waste heat, whereas 350° is considered the threshold for workable heat when dealing with steam turbines. And only about half the flue gas waste heat referred to above exceeds that temperature. However, Flat Glass, Petroleum Refineries, Hydraulic Cement, Blast Furnaces, Steel Mills, Primary Copper and Lime all discharge more than 50% of their purchased fuels and electricity as flue gas waste heat, with Flat Glass discharging more than 75 percent.[7]

The cost of utility-supplied power has a direct impact on industry's incentive to develop cogeneration. As utility-supplied electricity decreased in average cost from 2.7¢ a kilowatt hour in 1926 to 1.5¢ in 1968, industry had less and less incentive, not only to develop cogeneration, but to even maintain what they already had. The economics of their own locally-generated electricity could not begin to compete with the efficiency of the giant power projects of the 1930s and 1940s. Current increasing fuel costs, however, are reversing that trend, and new looks are being taken at development.

Existing levels of cogeneration are greatest in the energy intensive primary metals and pulp and paper industries (see Table 1). Primary metals are most important in the states

bordering the Great Lakes and in the South Central U.S. Some pulp and paper cogeneration occurs throughout all U.S. regions, but is most important in the South.[7] Figure 2 illustrates 1981 levels of development geographically.

Potential for cogeneration is greatest in several major industries: chemical, steel, petroleum refining, pulp and paper, food processing and textiles. These industries require large quantities of steam and account for about 75% of the energy use in the industrial sector.[8]

It may be seen that there is a significant amount of unused energy available for cogeneration. Development, in some cases, will be expensive, but current legislation goes far in increasing economic feasibility. The technology for exploiting this lost energy does exist but is still in its infancy. Further advances in this technology will occur naturally as incentives to do so increase.

Renewable Resources

There are many types of generating devices and fuel sources which qualify under PURPA. Current technology, however, dictates that only three types have the potential for becoming significant national sources of Cogeneration or Small Power Production. Broadly, they are Biomass, Wind and Hydropower. Other types, although included by PURPA, possess sufficient disadvantages to be excluded for the purposes of this Thesis. An example of such a type is Photovoltaic. Photovoltaic arrays

Figure 2: U.S. cogeneration capacity (mw).

TABLE 1: EXISTING COGENERATION CAPACITY (MW)

Geographic Areas	Food Products	Pulp and Paper	Chemicals	Petroleum Refining	Stone, Clay, and Glass	Primary Metals	All Other
A	94	238	184	0	15	0	385
B	18	31	166	9	0	451	32
C	35	83	135	21	0	0	410
D	59	406	292	44	76	1100	378
E	18	204	211	60	0	653	64
F	7	165	0	0	3	0	262
G	0	754	1031	656	37	1644	337
H	1	507	181	53	0	102	38
I	26	1028	93	183	2	140	148
Total	258	3416	2293	1026	133	4090	2054

Source: Latour, 1982

possess high initial costs, moderate maintenance costs, weather dependence, and they generate moderate amounts of DC power. Expensive state-of-the-art electronic equipment can convert this DC into a reasonable 60 cycle AC. The process used to do this, however, generates a number of harmonics, and the effect of these harmonics on a radial feeder has not yet been evaluated. Batteries and fuel cells have the same problem.

For these reasons, Biomass, Wind and Hydropower will be the power-generation types discussed.

Biomass

Biomass falls into several categories, each to be discussed separately. They are:

1) Industrial Waste Products
2) Forestry Biomass
3) Agricultural Biomass
4) Municipal Waste
5) Methane Recovery from Landfills

Industrial Waste Products, as a category, is most pronounced in the food services industry. The residue from such products as sugar cane, cereals, vegetables (corn in particular), nuts and citrus juices are all potential fuels under PURPA. The Environmental Protection Agency estimates that industries discard a total of about 137,000 tons per day of nonprocessing wastes, in addition to their already-mentioned waste heat. These can be dried and burned to produce energy. According to PURPA, any organic material not derived from fossil fuel qualifies as Biomass.

The primary disadvantage of this category lies in the area of boiler design. Many problems have been experienced with slagging and clogging. Recent progress in boiler design is reducing this problem, however, and the cost of these 'special boilers' is decreasing.

Forest and Wood Waste is cne of the more promising renewable fuel categories for power generation. In certain geographical areas, it has a lower cost per BTU than coal and it requires little in the way of equipment modifications or additions for combustion. It also has few problems with corrosion, emissions, or deposits. In 1980, it accounted for about 1.5 quads of U.S. power.[8] It is of particular interest where wastes have already been geographically concentrated, such as at a plywood mill or pulp and paper plant.

Wood-based biomass systems can frequently be combined (co-fired) with coal or oil with few changes in equipment and few, if any, adverse operational side-effects.

The energy content of wood (4,500 BTU per pound) is less than half that of good quality coal (12,500 BTU per pound), while the density of wood is lower. The transport cost for wood per BTU is therefore approximately double that of coal. So the proximity of wood-waste sources to a power producing facility is of prime importance. This factor alone effectively limits such facilities to New England, the North Central U.S. and the Pacific Northwest. These transportation costs mean that the wood products contribution to DES will vary considerably between local-

ities because of economics.

Further, for wood biomass, the removal of decaying material from forest floors may upset plant and animal life dependent on the presence of such material. Moreover, the initial effects of soil erosion may breed not only water pollution but also air pollution as topsoil is blown away. Since a 50 megawatt biomass-fueled plant may require up to 25 square miles of production land, these ecological consequences are not to be taken lightly.

There are success stories in this category: a 20 megawatt plant in Vermont using waste wood at a cost of $1-$2 per million BTU compared to $4-$8 per million BTU for coal (1980 costs); a 25 megawatt peaking plant in Minnesota, fueled by 80% coal and 20% wood waste, where wood cost $0.5-$0.6 per million BTU compared to coal's $1.5 per million BTU (1981 costs).[9] These are typical, but are only appropriate where the availability of wood-waste products is established and the cost of coal is only competitive, not presumptive.

Agricultural Biomass is probably one of the least promising of the categories. Although it falls under the definition of renewable fuels, it has many disadvantages and few advantages. The value of agricultural residue; corn, corncobs, cereals, grasses, stalks and stems, lies in its use as feed for stock. As a burnable fuel, it is on par with industrial food processing waste. Which is to say it requires special boilers and has slag problems. There is no foreseeable reason to expect significant development of this category as a fuel for electrical power

generation.

Municipal Waste takes several forms including solid waste from current and accumulated garbage and refuse collections and liquid waste from sewage treatment plants. The prospects of electrical power generation from sewage treatment wastes appear negligible at this time, so the discussion that follows will focus on Municipal Solid Wastes (MSW) and Methane Recovery from Landfills (MRL).

The Environmental Protection Agency estimates that 160 million tons of MSW was produced in the U.S. in 1982, or about 450,000 tons per day. At the end of 1982, 42 MSW plants were operating in the U.S. and processing about 2%, or 10,231 tons per day, of the total waste into electricity, steam, refuse-derived fuel, methane, or other products. Of these plants, only two (Madison, WI and Dade County, FL) had an output utilized for the production of electricity. They consumed 2,850 tons per day and generated, together, about 60 megawatts.[10] The contribution of MSW to electrical power generation was clearly negligible through 1982.,

Over 90% of the MSW plants either planned or actually under construction at this time are designed, however, to produce electricity. This is a clear change from the trend of 1982 and is thought to reflect the effects of PURPA on available market, government bureaucratic requirements and tax structure.

Drawbacks to MSW include the necessity for specially designed boilers to prevent slagging, the requirement to 'prepare'

this material (typically by cutting, chopping, sorting, drying or compressing) for use, its low energy content (4,500 BTU per pound) and its requirement for a significant amount of handling equipment. An EPRI study in 1977 concluded that organizations "are reluctant to use RDF because the risks are high and the return, in terms of an inexpensive reliable fuel supply in large quantities, is small or nonexistent." (Library of Congress, Issue Brief Number IB82063.)

Methane Recovery from Landfills (MRL) are in limited use in the United States today but their output is predominantly non-electric. There are 17 current MRL projects with 6.1 megawatts of capacity. On the other hand, another 17.5 megawatts is either under construction or planned, suggesting that PURPA may be inducing a shift in this area.

Existing landfills yield low BTU landfill gas, generally half methane and half carbon dioxide. This may be used as-is for steam or electricity production, or cleaned to pipeline standards.

It should be noted that there are 40,000 to 50,000 landfills in the United States that are amenable to MRL development. Roughly 600 cubic feet per minute of low energy gas (500 BTU per cubic foot) can be obtained from one million tons of landfill garbage.[10] The Resource Conservation and Recovery Act of 1976 requires that combustible gas concentrations must be less than 5% at the landfill boundary. It is expensive to meet this requirement by barrier installation, but extraction of this gas as

MRL under PURPA may not only bring the landfill into compliance with the Recovery Act but also provide incoming revenue.

Windpower

Windpower is probably the most widely incorporated private-use method of generating electricity in the United States today. Unfortunately, comprehensive data on the number of existing small, individually owned (residential, commercial or farm) wind machines does not exist. One indication of their popularity, however, is the amount of media coverage on the subject. Another is the number of interconnections between wind machines and utility power lines. Examples of both are the July 1982 issue of Popular Science, with an article listing 25 companies who sell small wind-power systems ranging in size from .5 kilowatts to 25 kilowatts, and the revelation that there are 260 operating units connected to the Rural Electric System alone, also ranging up to 25 kilowatts.[11]

Although these small wind machines qualify under PURPA, they make little impact on the national power grid. More significant are the large wind farms, usually located in more remote (thus less expensive) areas and adjacent to common rural radial feeders. These wind farms vary in potential from 20 kilowatts to several megawatts. Table 2 lists installed and planned capacity of wind farms in the U.S. by state. It may be seen that California leads the effort to develop this resource.

The initial capital cost of a wind-generator per kilowatt of

TABLE 2: WINDFARM PROJECTS
Source: Wind Industry News Digest, May 1983.

STATE	INSTALLED No. of UNITS	INSTALLED (MW) CAPACITY	PLANNED No. of UNITS	PLANNED (MW) CAPACITY
California	1,374	70.70	7,111	932.60
Oregon	1	.20	26	81.45
Montana	4	.10	45	53.00
Hawaii	57	1.40	117	4.70
New York	2	.01	2	.01
Rhode Island	3	.06	11	.20
Total	1,441	72.50	7,312	1,072.00

TABLE 3: CAPITAL COSTS FOR SMALL WIND GENERATORS
Source: Prichett, 1983.

SIZE (kw)	INSTALLED COST ($/kw)
1	$7,000
2	4,000
3	3,000
4	2,500
5	2,200
10	1,700
15	1,300
20	1,000
25	1,000

TABLE 4: SUMMARY OF CAPITAL COST ESTIMATES FOR LARGE WIND GENERATORS (excluding installation)
Source: JBF Scientific Corp. 1977.

MANUFACTURER	CAPITAL COSTS (1977$) ($/kw)
Honeywell	$698
SWRI	692
Aerospace	587
General Electric	499
Kawan	603
Lockheed	1,095

capacity generally declines with increasing size due to the economies of scale.

Table 3 gives capital costs per kilowatt for small wind-generators as reported by owners. Data for large wind machines is more uncertain due to these machines being in research and development stages, so more precise costs will not be available until more of these machines are in operation.

Table 4 summarizes cost estimates based on a survey of large generator manufacturers.[12] In general, a figure of about $1100 per kilowatt seems appropriate for large wind-generators.

In practice, these initial costs may be reduced in accordance with individual tax status. Federally, there is a 15% tax credit for business investments in windpower. This is due to expire in 1985 but legislation has already been introduced (S.1305 and H.R.3072) to extend the credit to 1990 and increase it from 15 to 25%. Also, there is currently a general 10% investment tax credit. Further, for residential applications, there is a 40% federal investment tax up to a maximum investment of $10,000. There are also state tax credits in many states. For example, there is a 35% tax credit for residential wind systems which cost up to $10,000 in Oklahoma. The result of all this is that an individual who bought a $10,000 residential wind-generator in Oklahoma would only have to spend $2,500.

Operation and maintenance costs and geographical location play a major role in determining whether a wind-generator will be economically successful. Annual operating and maintenance

cost, as reflected in a recent study, averages about 2.5% of initial cost, but some machines went as high as 14.8%.[11] These higher-maintenance machines would certainly be less cost-effective. The average annual wind speed is especially critical since wind energy is a function of the cube of wind speed. This means that the output energy doubles when the wind speed increases from 11 to 14 miles per hour.

A final consideration to add to the equation of wind-generation practicality is output sales price. When the producer sells to himself, he merely avoids purchasing the power from the utility, thus getting the same price that the utility charges for its electricity. If electricity is fed back into the grid, utility cost-avoidance under PURPA determines price. The July 14, 1983 issue of Energy Users Report related a survey of residential electricity rates across the country which reflected costs ranging from 1.6¢ per kilowatt hour in Seattle to 15.87¢ per kilowatt hour in New York City, with a median of 7.53¢ per kilowatt hour.

Small Scale Hydropower

PURPA defines Small Scale Hydroelectric (SSH) power producers, for the purposes of the Act, as being those whose generators are "located at the site of an existing dam, who uses the power potential of such dams, and who has no more than 30 megawatts of installed capacity."[13] FERC has somewhat expanded this definition by interpreting the "renewable resources"

clause of PURPA to apply to water used at both existing and new facilities of less than 80 megawatts. (45 Federal Register. 17966, March 20, 1980.) In any case, SSH is one of the most promising entries in the field of alternative energy sources.

There are several ways in which existing dams may be utilized to generate electricity. One way is to install turbines in the outlet works of the dam. Another is to use a large siphon to move water over a dam and through a bulb turbine. Yet a third is to reactivate existing hydropower facilities which have been closed due to non-profit, inefficiency or equipment deterioration. There is a significant number of this latter. Table 5 summarizes the number, size and location of those which the Department of Energy has determined have potential for redevelopment.

Many of the "retired" generators closed down when fuel was plentiful and power was inexpensively priced. What would not have been a profitable operation at that time might now be one. From a commercial perspective, the technology is available. Specialty rehabilitation companies, as well as turbine and generator manufacturers can readily refurbish this sometimes aged machinery. Further, turbines, which where previously uniquely designed for each site, have now been standardized by some manufacturers for SSH projects.[14]

Statistically, the Federal Energy Regulatory Commission stated in Order Number 70 that as of January 1, 1980, there were 1,384 hydroelectric plants in operation. Although this is a

TABLE 5: SUMMARY OF RETIRED HYDROPOWER PLANTS IN THE U.S. WITH SOME POTENTIAL FOR REDEVELOPMENT, BY GEOGRAPHIC DIVISIONS

Geographic Division[a]	Number of Sites	Previously Installed Capacity (kw)	Number of Sites Capacity Unavailable	Number of Sites by Capacity Range			
				<201 (kW)	201-1,000 (kW)	1,001-5,000 (kW)	>5,000(kW)
New England	1,397	348,549	695	355	284	56	7
Middle Atlantic	314	170,536	6	139	126	40	3
East North Central	445	212,319	28	221	140	55	1
West North Central	255	140,023	15	135	75	24	6
South Atlantic	185	138,933	3	54	93	33	2
East South Central	31	21,261	1	16	11	2	1
West South Central	22	11,893	2	7	8	5	-
Mountain	138	132,993	2	54	63	16	3
Pacific	125	77,952	2	58	46	17	2
TOTAL	2,912	1,254,459[b]	754	1,039	846	248	25

Source: U.S. DOE, FERC, "Staff Report on Retired Hydropower Plants in the United States, 1980."

[a]Bureau of Census Regions

[b]This is the capacity at about 2,200 sites. Capacity at the remaining 700 sites is not known at this time.

decrease from the 1,426 plants in operation in 1976, the installed capacity increased from 57,000 to 63,000 megawatts. Approximately 6,800 megawatts of this, or 10.7%, was generated from plants with a capacity of less than 30 megawatts. Further, applications to FERC for new development increased from 13 in 1976 to over a thousand in 1980.

It has already been indicated that there was 1,254 megawatts of "retired" installed capacity in the U.S. A government study has also determined that there are dams in place that could be developed for hydropower in the amount of 55,000 megawatts (U.S. Corps of Engineers, Institute of Water Resources, National Hydro-electric Power Study of 1981). Approximately half of that potential is at small dam sites.[14]

There are several advantages to the development of hydropower. It can be brought on-line more quickly than conventional power plants. It is non-polluting and has no fuel costs. Operation and maintenance costs are comparatively low. The technology is well-developed and reliable. And various tax advantages may be realized.

On the other hand, most of the best sites for SSH are already in use. Also, the compliance with water laws and land-use legislation further limits the remaining sites. The resulting remote locations mean additional costs for access roads, transmission facilities and substations. A high initial cost for property and access rights, initial construction and equipment is a part of SSH. Finally, the weather dependence of

SSH means that a year or two of dry conditions after dam construction could be disastrous for investors.

Chapter Summary

There will be several types of power-generation equipment to which electrical utilities must be prepared to connect as a result of PURPA. The most significant of these appears to be wind farms and small-scale hydroelectric facilities. Major industrial facilities, particularly those in metals, petroleum and flat glass, have the potential for being the more common supplier of 80 megawatt sources to be incorporated into the grid. But they will normally be in an urban or industrialized area, not miles out on a radial feeder. The industrial ring feeders common to industrial areas (and large shopping centers and office buildings) generally provide overcurrent protection from both directions, and as such will not possess the same problems of incorporation as rural radial feeders.

CHAPTER IV

PROTECTIVE DEVICES AND PRESENT COORDINATION TECHNIQUES

General Discussion

Except for some limited industrial cogeneration, public utilities have historically exercised complete control over the generation, transmission, and distribution of electricity in the United States. That control has contributed to the laudatory record of safe and reliable operation compiled by these utilities. With the advent of PURPA, the utilities have lost a measure of that control and are concerned that safety and reliability might suffer.

Some issues concerning the connection of DES to the utility grid are simple and easily agreed to by all parties. An example is the absolute requirement for the safety of linemen. Other issues are less clear. What, for example, is an allowable level of harmonic distortion? Still other issues are economically driven. Is utility-grade equipment really required or is lower-cost, industrial-grade equipment acceptable?

Interconnect costs are extremely sensitive to system size. A 5 kilowatt system has an interconnect cost of more than $300 per

kilowatt, whereas a 100 kilowatt system has an interconnect cost of only $63 per kilowatt.[15] And because these costs must be borne by the small power producer, he will seek to minimize wherever possible.

Utilities have designed feeders and specified circuit breakers, fuses, sectionalizers and reclosers configured radially. Coordination of relays, fuses and reclosers for a radial system is easy to accomplish, with the associated techniques being well known and available from many sources. But the addition of various types of generation and storage devices such as wind generators, photovoltaics, storage batteries, and synchronous and induction generators on distribution feeders will cause the typical radial feeder to have multiple electrical power sources. This arrangement will require changes in the selection and coordination of circuit protection devices. The fact that it may be characteristic of the feeder for one portion of the day to be dual or multiply fed, and then for another portion of the day to become strictly a radial system compounds the device selection and coordination problem. Automatic reclosing, fusing and equipment momentary and interrupting ratings must be re-examined in light of DES.[16]

Distribution Systems

An electric utility's distribution system is generally considered to extend from the distribution substation to the consumer. Figure 3 offers a typical system. At the distribution

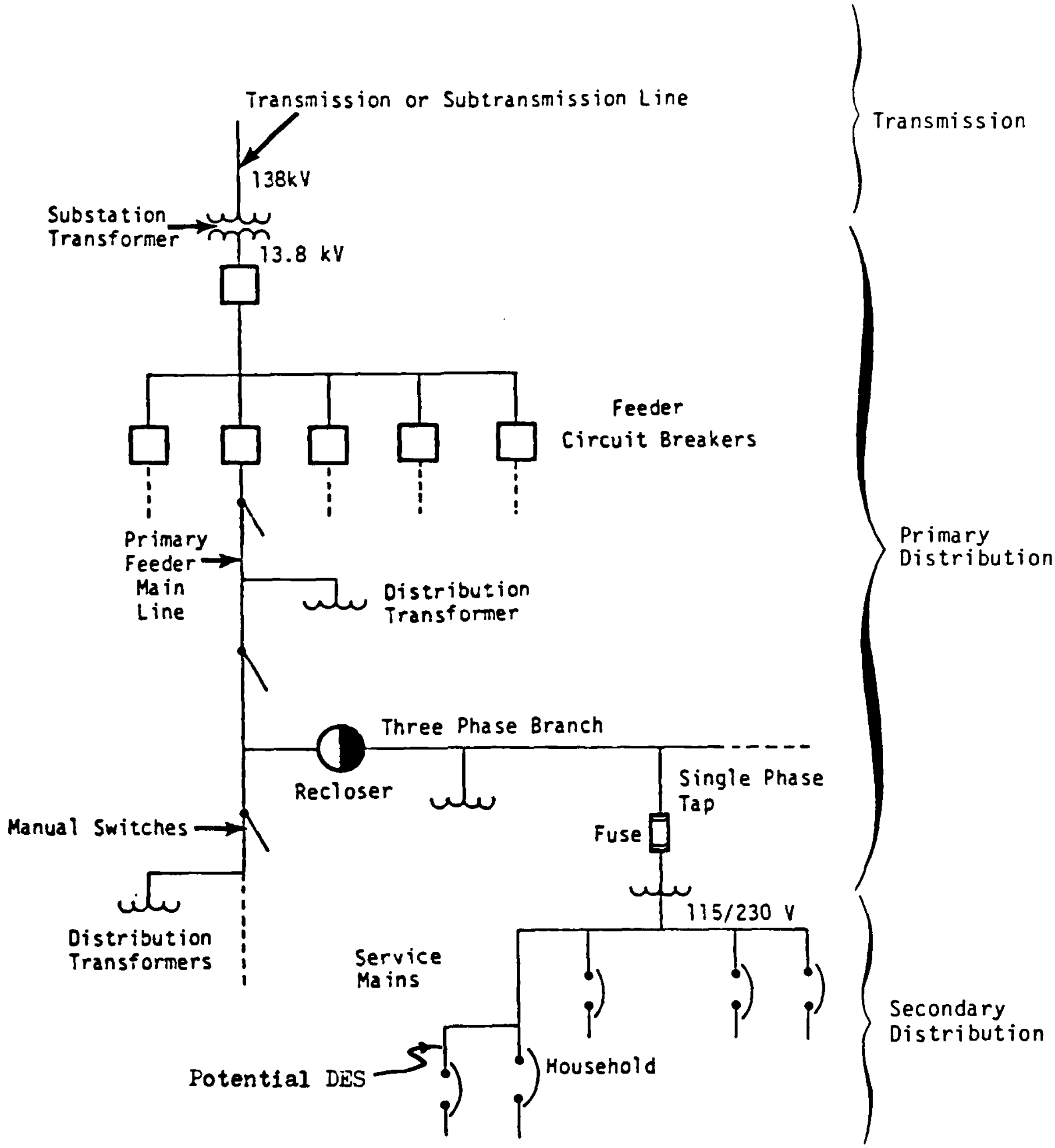


Figure 3. Typical Distribution System

Source: Science Applications, Inc., November, 1982

substation, a transformer converts the transmission line voltage (typically greater than 30 kV) to the distribution primary voltage (usually between 11 and 17 kV) which will generally be fed to five to ten radial feeders. Loads and voltages are measured and recorded at the substation. Protective relays are installed to open feeder circuit-breakers for any abnormal line condition. In most cases, voltage regulation equipment is installed to maintain the distribution primary voltage within a certain range as the feeder load changes.[15]

In a populated area, a feeder may supply power to several neighborhoods. In a rural area, a feeder may be more than thirty miles long and a significant portion of the load may be line losses. It should be noted that it is these latter feeders that may realize the most impact from small power production facilities. Each radial feeder consists of a three-phase main line (or "backbone") with the possibility of several three-phase branches and the near-certainty of a number of single-phase taps. One single-phase tap may supply (in urban areas) five to ten homes. Distribution transformers convert primary voltage to customer voltage.

System protection is designed to maximize safety, minimize equipment damage and optimize customer service. The major devices used to accomplish this are the relay-operated circuit-breaker, the recloser, and fuses. All respond to current and are designed to de-energize faulted circuits before damage occurs. In order to cause a service outage to the smallest number of

customers, the time-current characteristics of these protective devices are coordinated (specifics on these characteristics will be discussed in a later section). The resulting effect is that of the device being closest to the fault, upstream, being the one that opens the circuit. Only downstream consumers should then be affected.

As feeder load increases, feeder voltage (without compensation) will decrease. Appliances and motors at the end of the feeder may be damaged by this low voltage. Therefore, some means of voltage regulation must be used. Utilities accomplish this by, first, increasing voltage at the substation via a tap-changing transformer. This, however, will only be effective so long as the sending end voltage has not become high enough to damage customer equipment at that end of the line. To provide for this event, a voltage regulating transformer is incorporated partway down the feeder. These transformers are responsive to load and will adjust the feeder voltage as the load changes.

Line current is made up of two components, a real component that performs work and a reactive component that magnetizes motor windings to allow work to be performed. Reactive load is provided by substation or feeder capacitors. When capacitors supply the reactive load, the line current on the generation side of the capacitors is reduced, but the same amount of work is done. The "power factor" is increased, or the line has become capacitor-compensated. This reduces line currents, thereby reducing voltage drops and line losses.

Protective Devices

A fault in an electrical circuit is any failure which interferes with the normal flow of current. The two types of faults are shorts and opens. Shorts are an unintentional electrical connection between a supply conductor and another conducting medium which results in high current flow in the supply conductor. Opens denote a discontinuance in the conductor which results in no current flow. Of the two, shorts are by far the most damaging to equipment.

So protective devices are generally current-sensing units which seek to determine if a conductor is passing an abnormally high amount of current and, if so, to stop that current flow. These devices may also be divided into two categories, one of which only seeks to limit current flow (reactors ana resistors), but we will address only those which open the faulted circuit. This category includes such components as overcurrent relays, circuit-breakers, reclosers, fuses and sectionalizers.

<u>**Overcurrent Relays**</u> for distribution system feeders normally close a set of contacts in reaction to the sensing of high currents in a conductor. This action completes a circuit tripping the feeder circuit breaker. The relay functions as follows:

1) A current-transformer has its primary connected in the power circuit of the conductor in question and its secondary providing power to the relay.
2) The relay, basically a single-phase motor making use of the "split-phase" or "shaded-pole" principles, applies

torque to a disc which is acting against a retaining spring. The disc possesses adjustable moving contacts which can make or break, completing a circuit.

3) When the power from the current-transformer exceeds the preselected combination arrangement of spring-adjustment/torque-setting/contact-location in the relay, the contacts will close, energizing the circuit-breaker and causing it to trip.

Usually, an overcurrent relay has at least two simple adjustments. One is a "time-dial setting" which adjusts the arc of travel the disc must traverse before closing the trip-coil contacts. The other is a "tap-block setting" which is a series of input power transformer taps capable of widely varying the input power the relay-motor sees. These adjustments allow a great deal of latitude in the applications for each model of relay.

Overcurrent relays possess an inverse time-current characteristic which will permit small, short-duration overcurrents to pass unhindered. Conversely, very high currents will cause very fast responses. So it may be said that moderate currents for longer times, or higher currents for moderate times, will suffice to close the contacts. Time-current curves indicating precise operating times are published by each manufacturer.

Oil Circuit Breakers and Oil Circuit Reclosers (OCBs and OCRs) are similar in purpose and operation, so will be addressed together. In general, there will be one OCB on a feeder, where there may be several OCRs. The OCB will be the "master" breaker

for the feeder and will be adjusted to the highest overcurrent tolerance of all the protective devices. The OCRs will be serial on the feeder, with diminishing tolerances downstream. This will result in the OCR furthest downstream, prior to a fault, being the one to open the circuit.

OCBs with reclosing relays and OCRs are devices designed to go through a series of operations in the event of a fault. From 75 to 90% of all faults are temporary.[17] So these units act to temporarily remove power and give the fault a chance to clear itself. They do this by repeatedly removing and reapplying conductor power. The magnitude of current which causes a device to remove power, the duration of time before reclosure, and the number of reclosures are all adjustable. If the final reclosure fails to find a cleared fault, the unit will lock out.

OCR reclosure adjustment is accomplished in the following manner. A typical unit will allow four reclosure operations. The manufacturers have named the sensitivity, or response time, of each operation with the letters A through D, with A being the most sensitive, or fastest, operation. So a unit that was adjusted for 3 A operations and a C operation (hereinafter referred to as 3A-1C) would quickly cycle through its first three power removal operations, more sedately make one more closure attempt, then lock out. Observe that this makes it very simple to coordinate devices. Two identical units incorporated into a feeder might be set with the downstream unit on 3A-1C, with the unit next upstream being set at 2A-2C. Many variations on this

theme are possible. Further coordination methods may be based on manufacturer's amperage ratings, locating a 70-amp unit upstream from a 50-amp unit for example.

Fuses are generally familiar to all of us and increasing their size makes no difference in their principle of operation. A fuse operates on the "weakest link" theory. It is advantageous to make the weakest link in a system controllable, maintainable, visible and economical. Utility fuses are placed in-line in the conductor and contain an element that will destroy itself in a predictable manner should the current it must pass become too high. Ideally, the last non-self-destroying protective device in-line prior to the fuse should be coordinated to remove temporary faults before allowing the fuse to destroy itself. Fuses have inverse time-current characteristics similar to those of overcurrent relays.

Sectionalizers are somewhat different than the other devices mentioned in that they will not interrupt a fault, but only open when a line has been de-energized by some other device. They will perform in the same way as a fuse but are more expensive. a sectionalizer's value lies in the fact that where a fuse must be replaced after operation, a sectionalizer does not. So on particularly troublesome lines, sectionalizers may be used to replace fuses.

A sectionalizer is placed in the line downstream from some protective device, such as an OCR, where it will sense the fault current and count the number of times that device removes power

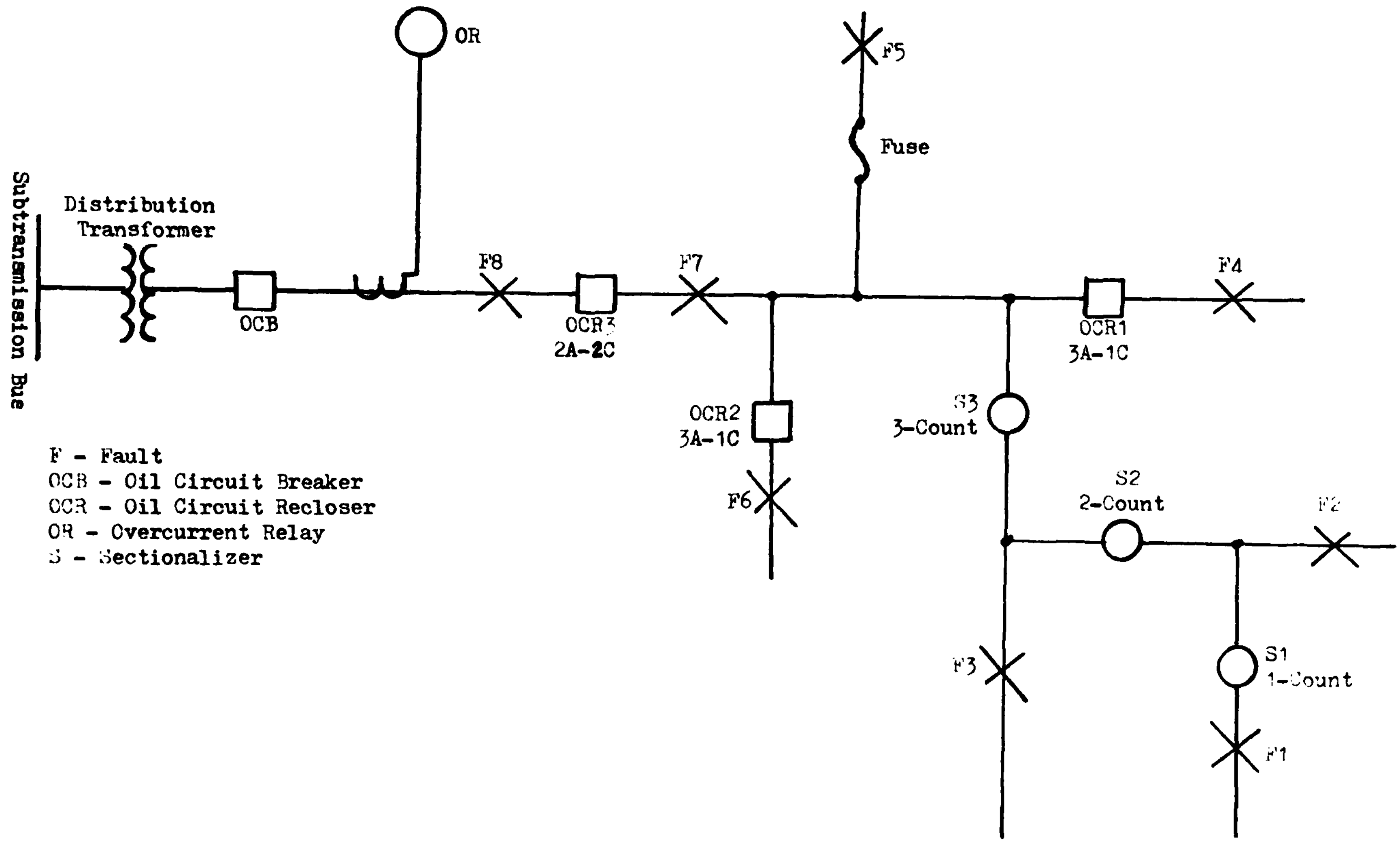
in the event of a fault. After some preset number of power interruptions within a specified time, the sectionalizer opens, after which it must be reset manually. The opèration is like that of a fuse, with no material costs afterwards.

Coordination

A coordinated system is one in which the protective devices are set to operate selectively so that the one nearest the fault (but upstream) operates first to de-energize only the faulted portion of the system. If this particular device fails to operate as desired, the next device in the protective chain must be ready to perform. In a properly coordinated power system, these protective devices will be either tailored to requirements or adjustable over an appropriate range of operation to insure that they can both recognize a fault with the minimum overcurrent and remove the smallest number of consumers from the feeder in the minimum possible time.

A proper coordination scheme is best illustrated by example. Refer to Figure 4. This figure depicts a typical radial distribution feeder with its major protective devices incorporated. Various faults have been placed on the feeder and its branches. These faults will be exercised, one at a time, to demonstrate their effect on a properly coordinated system.

Should a fault occur at F1, OCR3 will cycle through one short A operation and sectionalizers S1, S2 and S3 will count one interrupt. S1, however, is set for a one-count and lockup, there-



F - Fault
OCB - Oil Circuit Breaker
OCR - Oil Circuit Recloser
OR - Overcurrent Relay
S - Sectionalizer

Figure 4. Typical Simplified Radial Distribution Feeder With Major Protective Devices.

fore it will open, removing the fault.

Should a fault occur at F2, OCR3 will cycle through a short A operation while S2 and S3 will count one interrupt. OCR3 will then reset and again sense the fault, causing it to cycle through another A operation. S2 and S3 will count again, but the 2-count preset S2 will then lock out, removing the fault. OCR3 will reset, re-applying power.

Should a fault occur at F3, OCR3 and all three sectionalizers will perform as described above. When OCR3 resets for the second time, however, it will still sense a fault. Having completed its two A operations, it will begin the more extended C operation. At this time, S3 will complete its 3-count and lock out, removing power from the faulted branch. OCR3 will again reset and, sensing no fault, recycle to a ready mode.

Should a fault occur at F4, good coordination requires that OCR1 operate through all three of its A operations and into its C operation before OCR3 experiences its first A operation. OCR1 should provide lock out and fault clearing before OCR3 completes any of its C operations.

Should a fault occur at F5, OCR3 should be set to cycle through its A operations without the fuse opening. The inverse time-current characteristics of the fuse should tolerate a slightly higher time-current magnitude than an A operation of OCR3. This allows temporary faults to be cleared by automatically resetting devices. On the other hand, if these two A operations do not permit the fault to clear itself, the time-

current tolerance of the first C operation of OCR3 should be well above that of the fuse resulting in the fuse opening and clearing the fault. OCR3 will then recycle to a ready mode.

Should a fault occur at F6, OCR2 should react exactly as OCR1 did for a fault at F4, assuming they both have the same current rating.

Should a fault occur at F7, coordination can be obtained by simply insuring that the OCB will not trip before OCR3 completes its series of operations. A larger relay setting than the time-current characteristic of OCR3 will accomplish this.

Should a fault occur at F8, the OCB in combination with the overcurrent relay provides protection in the manner already described. It should be noted that for a fault at F8, coordination is no longer a concern. The only circuit protection left, the OCB, is going to remove power from the whole feeder.

Conclusion

Given the design of radial feeders on the national grid today, it is apparent that the incorporation of any appreciably-sized DES will be grounds for system analysis. Design re-evaluation, with emphasis on the effectiveness of installed protective devices, will need to be performed on any radial feeder used to incorporate significant multiple power sources. While all agree that PURPA requires the costs for feeder modifications and protective relaying to be borne by the qualifying facility, determinations must be made as to quality requirements, main-

tenance and testing requirements, and the assessments to be made on the qualifying facility should an entire feeder redesign be necessary.

Quality of materials, reliability of design and high level of maintenance have all contributed heavily to the economy and efficiency of the electrical power we all take for granted in the United States today. A good deal of thought should be given to the best ways of modifying a system that works this well.

CHAPTER V

STABILITY AND RELIABILITY CONSIDERATIONS

General Discussion

Stability is that characteristic of a system which is a measure of its ability to resume stable operation after being impacted by some external phenomenon. The greater the phenomenon, the higher stability must be in order for a system to heal itself. In electrical power distribution systems, stability can be measured by observing the reaction of a system to a high-magnitude step function, such as a short-circuit or a load-drop.

By its definition, power system stability denotes the tendency of the various synchronous machines within the system to remain in synchronization with each other. Any tendency to fall out of synchronization, then, denotes a degree of instability. It is this tendency which must be guarded against.

Reliability can be defined as the probability that a system will perform its designed function for some period of time, under whatever normal operating conditions may be encountered. Reliability may be determined at all levels, component, circuit or system. It is normally derived by applying statistical analysis

to component or design history. So in power distribution systems, reliability is a measure of the probability that, at any given time, 60-cycle, nominal-voltage power will be available throughout the feeder.

Because reliability is a measure of all the factors affecting the end-product, it can be seen that stability falls under the umbrella of reliability. So discussions of reliability must necessarily include stability. Therefore, the discussions which follow will address reliability and stability together, except where it is necessary to differentiate in order to insure clarity.

Dispersed Energy Source Impacts

Power quality is a distinct area of reliability for which utilities have voiced concern in reference to the incorporation of DES. Subareas of quality are power factor, voltage, frequency, harmonic distortion and flicker. Each of these factors is heavily influenced by DES system cost, with utility grade equipment being the most expensive.

Power Factor: Line commutated inverters and induction generators used by DESs will need reactive power (VARs) to operate. And although these VARs are not registered on a KWH meter, someone will still need to supply them. Depending on the size of the DES, capacitors already in place may or may not be satisfactory. It will be the responsibility of the DES to provide capacitance

adequate to their equipment needs. Utility options range from treating the DES as a normal load and requiring a power factor of .85 to treating the DES as a contracting utility and requiring a power factor of 1.0. In any case, this is an expense for the DES.

Voltage: This area is self-explanatory and only tolerances for parallelling need be addressed. With the exception of large DESs at the downstream end of long feeders, the connection of a DES to a utility can be viewed as a connection to an infinite bus, and the utility will establish the voltage.

Frequency: This, too, may be viewed as controlled by the utility after paralleling. It also emphasizes the DES need for appropriate paralleling equipment.

Harmonic Distortion: Harmonics, on U.S. power systems, are waveforms whose frequencies are multiples of the fundamental, 60-Hz, waveform. There are both voltage and current harmonics, each with its own characteristics. Voltage harmonics can adversely affect customer motors and transformers, while current harmonics can cause capacitor bank overheating, electronic equipment interference and communications interference.

No in-depth studies have been performed to establish acceptable levels of harmonic distortion from DESs. A major concern about DC sources, however, is the current-harmonics that are generated from line commutated inverters. So photovoltaic,

fuel cell and battery reservoir DESs must make a choice between line-commutated inverters and the more expensive self-commutated inverters, knowing that the latter produce little harmonic current.

Although no limits for harmonic distortion have been established, several possibilities have been suggested. One is to develop limits for each individual harmonic wave, such as to limit the third harmonic to 5% of the fundamental. Another is to require that the RMS harmonic content be equal to or less than some percent (such as 10%) of the fundamental.[18] Many utilities have adopted the recommendations of IEEE in their interconnection requirements and required total harmonic distortion of less than 5% in current and less than 2% in voltage.[15]

Flicker: Voltage flicker is a term commonly used to describe a significant fluctuation of customer voltage caused by a rapidly fluctuating load. The obvious result to customers on a feeder are a visible flickering of lights and the shrinking or expanding of television pictures. Less visible, but more serious, are problems experienced by digital electronic equipment and computers. Offending customers are sometimes required to take corrective action to prevent their equipment from causing flicker on a feeder.

It is impossible, both for the utility and the DES, to design or build a totally flicker-free system. The utilities know that and many presently have voltage flicker limits imposed on all

customers. Where DESs are concerned, induction and synchronous generators are often started as motors and then operated as generators once they have reached full speed. This type of starting, particularly on large generators, may produce excessive flicker on the feeder.

One method for solving flicker problems for DESs is to require a dedicated transformer for interconnection. This, however, would be expensive and utilities have not generally adopted strict interconnection policies on flicker. It is felt that such policies are unnecessary. Utilities appear to feel that current flicker voltage standards, such as those determined by Estimators Guide G5326, already apply to intermittent and fluctuating loads and consider DES to be a member of this category.

Another factor concerning feeder reliability after incorporation of DESs is whether the qualifying facility is willing to coordinate their scheduled maintenance with the utility. This coordination can increase the utility's ability to plan power control and increase reliability. Further, what level of maintenance is the DES willing to perform, and capable of performing, on its own equipment? Decreased willingness or ability can mean decreased reliability.

What type of fuel does the DES depend upon? Is it sporadic (wind)? Is it seasonal (hydro)? Is it predictable? If the utility can't perform its planning with some degree of certainty, it will have little reliability. Therefore, it must use 'spinning

reserve' to compensate for any unpredictability inherent in DES output.

Inspection, test and maintenance are areas of significant interest in the subject of DES incorporation under PURPA. With the motivation offered by the Act, it is reasonable to assume that DES owners will range from those with little or no experience in the field to those fully qualified to inspect, test and maintain all of their equipment. It is therefore imperative that the utility work closely with each DES and supplement, where necessary, that owner's expertise.[18]

Where the interconnection is concerned, the utilities should require both an initial acceptance inspection and test and subsequent periodic inspections and testing. A complete set of drawings and equipment specifications should be available to both parties. The utility must reserve the right to inspect on demand all protective relays and circuit breakers, and should have the right of sole access to one condition-visible master switch to remove DES power from the feeder in the event of emergencies or maintenance.

Where maintenance is concerned, each party is responsible for the maintenance of its own equipment. Both parties, however, may find it advantageous to allow the DES owner to contract for some or all of the DES maintenance with the utility.

Reliability assessment can be done in various ways for conventional electrical power systems. One method is to calculate the probability, using historical data biased with recent per-

turbations, that there will be a feeder failure (open circuit-breaker, failed transformer, blown fuse, ect.) which will result in losing the load. This "Loss-of-load Probability," or LOLP, attempts to take into account all scenarios for load loss and, from its results, determines the necessary capacity for the feeder. General Electric produces a computer program to perform these calculations, as does Argonne National Laboratory and the Electric Power Research Institute (EPRI), among others.

Programs dealing with specific stability problems are also available. AESOPS1 and AESOPS2 use a very powerful analytic technique called frequency domain analysis. These programs calculate the potential for setting up spontaneous oscillations in an electrical network. A transient stability diagnostic program (TSDP1) is also available through EPRI.[1]

In a study prepared by System Control, Incorporated,[19] it was found that many conventional reliability analysis methods can be extended to handle DESs, this being evaluated on a variety of methods ranging from an exponential approximation suitable for rough hand calculations, to sophisticated statistical methods used in computer analysis. They (SCI) believe that many of the questions relating to DES reliability derive from a paucity of data rather than a deficiency in analytic methods.

It should be pointed out that the software referenced can be expensive. EPRI[1] notes that it may cost several hundred thousand dollars to run a full set of stability analyses for a utility system in anticipation of DES incorporation. It can also be said,

however, that if the cost of just one transformer (at $1 million for 1000 MVA) or one mile of high-voltage transmission line (at $750,000) can be avoided, the full investment can be recouped.

Conclusion

Simple models have already been developed which may be used to evaluate the service reliability of power distribution systems with DES, suitable for conceptual studies. They confirm most of the intuitive aspects of reliability concerning the range of DES encouraged by PURPA.[19] Various computer programs are commercially available with which the utilities may simulate the incorporation of a DES on a portion of their system in order to predict impact.

Further studies should be performed to establish the level of penetration of DESs on a feeder which should trigger sophisticated analyses of potential impact on reliability. Very small DESs should make little impact, no matter what they do. Very large DESs, particularly on long or low-power feeders, may make significant impacts. Can a percentage of back-bone feeder power be used as that trigger-point? Or will it take an equation involving the number and sizes of other customers on the line? It may be completely unnecessary to crank up analytical machinery in 90% of the DES cases.

If the DES is unpredictable, the utility may be required to operate a spinning reserve of roughly the same capacity as the DES to insure system reliability. If so, how will 'cost avoid-

ance' be determined in order to establish rates for utility purchase of DES power? If reliability is a principal factor, the buyback rate will suffer.

System reliability is not a fixed parameter. Generally, systems can be made more reliable by increasing the level of component redundancy and the reliability of individual components, by increasing the quantity and quality of maintenance, or by designing the system to allow greater flexibility. The drawback in all these areas is increased cost. So the real problem is to strike the proper balance between system reliability and system cost. This, then, defines one of the major DES factors governing reliability after interconnection.

CHAPTER VI

DISPERSED ENERGY SOURCE INCORPORATION CONCERNS

General Discussion

When concerns generated by PURPA are brought to issue, it must be remembered that the relative importance of each concern, or even its very right to existence, is subject to the point of view adopted. From the point of view of the public, safety and reliability are paramount. From that of the fledging small power producer, practicality and profitability must be the driving considerations. From the point of view of the Utility, continuity of service, reliability of equipment, and safety of maintenance personnel take precedence. These points of view are not necessarily mutually exclusive. There is, however, a major difference in emphasis on the issues which follow.

All parties agree that safety is of prime consideration. There is, however, no such thing as perfect safety. The amount of personnel safety characteristic of an electrical system is on one side of an equation balanced by cost, maintainability and accessibility on the other side. No fault is found with this necessity for practicality, but it still must be recognized that

although a system is considered 'safe' it is still somewhat less tnan 'perfectly safe.' And the difference between the two is largely determined by who is paying for what, versus who is in control of what. In other words, safety is a major issue which is colored by point of view.

It is fairly simple to assert that a DES is responsible for any cost incurred by the utility associated with the interconnection of the DES to the power grid. It develops, however, that there are many 'gray' areas after this assertion is made, resulting from increasingly remote potential costs from a cascade effect due to the interconnection. Instead of a step-function which allows one to assert that everything on one side is the responsibility of the DES, while everything on the other side is the responsibility of the utility, there is a blending of causes and responsibilities for costs associated with interconnection from one side of the delineating assertion to the other. Again, point of view becomes critical in the decisions governing responsibility.

The following concerns are representative of the 'gray area' issues for which current guidance is either incomplete or non-existent. The list is by no means complete.

Concerns

In most distribution systems today, opening the distribution primary circuit breaker removes electrical power from every component in the feeder system. The incorporation of DES

changes that. Modified equipment will hold the potential for remaining electrically charged with the DES as a source. This has already been discussed and will not be further addressed. 'Possible remedies' is the concern to be discussed.

Utilities are concerned with the safety of line crews. DES equipment manufacturers and DES owners are concerned with DES safety (to include questions on DES legal liability). In the event of a fault on the feeder, all parties agree on the necessity for an automatic switch to disconnect the DES from the feeder. But what about the necessity for redundancy? The utilities generally design several steps of protection into their systems. Does this practice mean that the DES will be required to incorporate a second circuit-breaker for use if the first should fail? These breakers are not inexpensive. What about the fault-detection system to control these circuit-breakers? It is certainly fair that the DES purchase a circuit-breaker to protect against a fault in either its own equipment or that of the utility. But who should pay for the redundancy if that redundancy is a utility-imposed requirement and for a utility fault?

As a result of interconnecting with DESs, utilities want to permanently mark all feeders, distribution transformers and components as "multiply-sourced" if that feeder is connected to a DES. The purpose of this is to alert any maintenance personnel to the potential dangers of working on this equipment. Should the DES be required to pay for this effort? The DES is already going to be required to pay for a visible, lockable disconnect

switch in most cases. Why should they also have to pay to tag every component on the feeder?

On the other hand, from the utility point of view, this simple tagging is one of the most effective safety steps possible. It will tell a repairman to insure that the line is 'dead' from both directions. It is inexpensive (to a utility). And it would be unnecessary except as a direct result of incorporating the DES. Therefore, it is the DES's responsibility to finance the effort.

Utilities further assert that the visible switch in the interconnection from the utility feeder to the DES must be operable by utility personnel at any time without notice to the DES and without any restrictions on access, that it must open all connections between the two parties (including neutral), and that it must be lockable in the open position by the utility. This effectively places total control of the interconnection with the utility. Few DESs have problems with this concept.

A further 'gray area' concern of the utilities is that the proliferation of DESs on a utility's electrical system could significantly impact the manpower (and other) costs in the disconnect and lock-out of a DES for line maintenance, clearance, construction or power outage occurances. They envision, in rural areas, linemen being required to travel through several counties just to insure that a portion of a feeder remains de-energized while personnel perform their required functions, then having to repeat the travel effort to re-energize the

feeder. Obviously unable to predict such costs, they wonder how best to recoup them under PURPA.

All protective equipment on the utility distribution system is designed to withstand a maximum-rated fault current. If subjected to currents beyond this rating, explosive damage may occur. Fault currents may be additive. A DES may contribute to available current at a fault to a point where the ratings of protective equipment are exceeded. If a large DES is to be incorporated on a feeder, the utility may need to evaluate the duties of protective equipment for the necessity of upgrading. Utilities feel that this is strictly the responsibility of the DES. Some DESs feel that this merely pinpoints existing weaknesses in the utility system.

In the case where utility equipment must not only withstand additional fault current, but must also interrupt it, equipment replacement is most likely. Figure 5 illustrates a way this condition might occur. Breaker B must withstand and interrupt the total fault current from both the utility and the DES. Although the generator breaker could interrupt the fault current before B trips, it must be coordinated to wait until B opens. Otherwise, the DES might trip for faults on other substation feeders. If B cannot withstand the additional fault current, i.e., its momentary duty rating is exceeded, it must be replaced. If B must be replaced, the other feeder breakers may also need to be replaced.[15]

Another concern that may not have clear definition is that

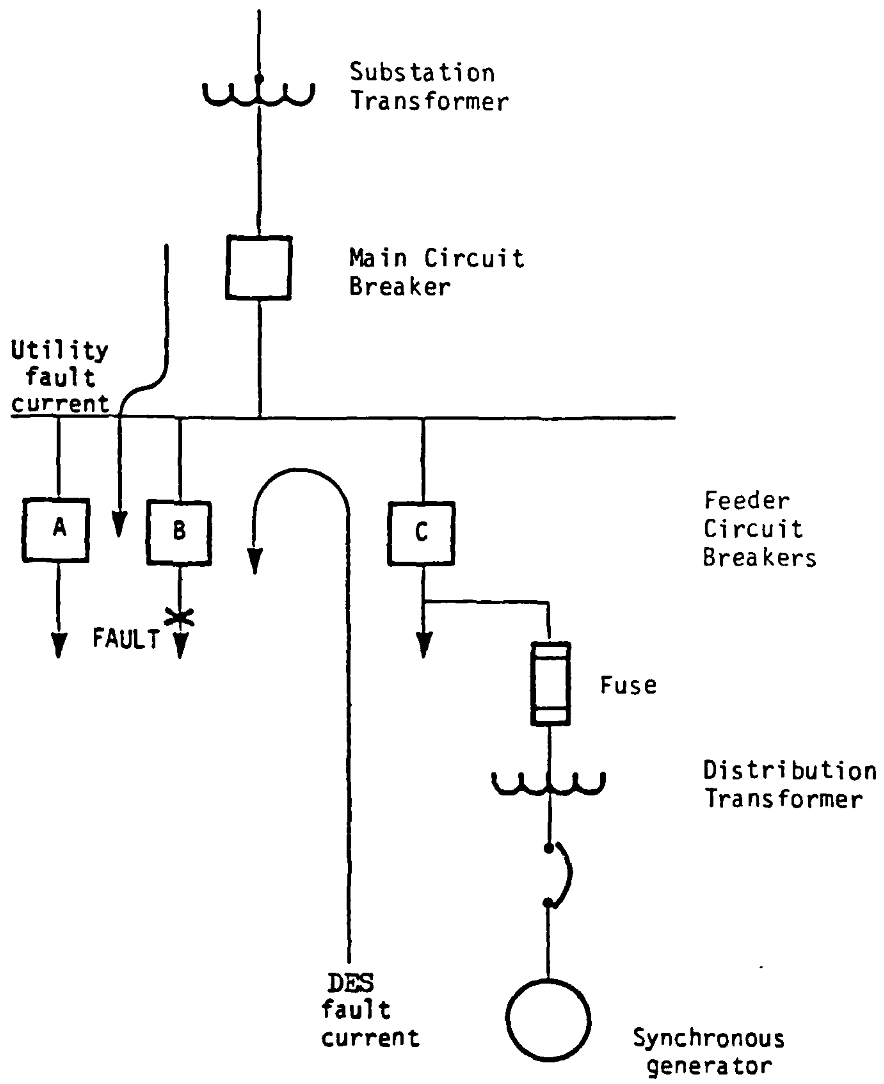


Figure 5. Example Showing Increased Fault Duty Because of DES

Source: Science Applications, Inc.

the utilities will probably require the use of an auto-synchronizing relay for interconnection with the DES. This, even though synchronized closing of the DES generator breaker can be achieved manually. The reason for this requirement is the protection of customers sharing the same transformer as the DES, along with the protection of utility equipment. The utilities want phase, frequency and voltage identity prior to paralleling.

The problem with the foregoing requirement, where the DES is concerned, is that auto-synchronizing relays generally require a circuit breaker that can be closed electrically. Most small circuit breakers rated 600 volts or less are manual, so it may be necessary for the DES to obtain a much higher-rated breaker than that required by design in order to get the auto-close feature. An auto-synchronizing relay, oversized breaker, and any synchronizing controls particular to the DES design will increase interconnection cost even more for the DES.

The primary tradeoff in relay reliability is between cost and quality. Many utilities consider finely-engineered electro-mechanical relays the best and most reliable. These relays are expensive and require regular maintenance by an experienced technician. And because the utility imposes these quality requirements on itself, it certainly seems fair to impose the same requirements on DESs. In some cases, the utility may even purchase, install and maintain the relays, charging the DESs all costs.[15]

On the other hand, utilities may be willing to accept solid-

state electronic relays. These lower cost, lower maintenance devices have generally been accepted in industrial applications, where service to other customers is not a consideration, and where the value of the protected equipment does not justify a larger investment. It is too early to predict whether this equipment will win widespread support among utilities.[15]

It is noted by EPRI that the size and cost of most DESs will not justify utility-grade relaying. If such a requirement should come about, the cost-effectiveness of many DESs will fall into question. A utility-controlled inspection and test program may provide a solution to this dichotomy.

Another issue which falls in the 'gray area' is that of requiring the DES to supply a dedicated transformer. This is also a high-cost item for the DES. A 15kVa transformer, for example, costs nearly $1,000. While the utility feels it necessary to provide reliable service to other customers on the same transformer, this potential requirement is a high-significance factor in the decision of whether to build a DES or not. Therefore its practical resolution is certainly included in the intent, at least, of PURPA. Perhaps the answer to this particular problem is for the utility to establish a limit on the capacity of a DES which is allowed to share a transformer with other customers, with relaying providing fault-current protection.

Conclusion

Interconnection cost between the DES and the electrical utility is presently the issue with the greatest number of unknowns. Solid cost data must be available before many potential DES developers will make decisions on actual construction of facilities. But both requirements and costs for this interconnection will vary in accordance with the resolution of a number of concerns. Compounding the problem will be strictly local resolution of certain issues which will provide no precedence for use across state lines.

Within the penumbra of 'interconnection costs', safety hazards potential in the isolated operation of a DES are the greatest current technical concern. Also, further evaluation is required relating to the technical issues of harmonics, power factor correction and appropriate DES protective switchgear. The necessity for dedicated or isolation transformers is an important concern of potential DES owners.

Some of these issues are more straightforward than others. Resolution may be simple and only the 'authority to impose' will be needed. Others don't seem to have any obvious resolution. In these cases, perhaps a small board should be convened to resolve each issue. Three members should be sufficient, with one from the public utility, one from the small power producer, and one, with pertinent expertise, from local industry (NOT a member of the Public Utilities Commission nor an appointee of that group, who may have vested interests in either direction). This latter

member might be agreed upon by both other members as being unbiased and possessing the requisite expertise.

In any case, some form of resolution of the 'gray area' issues must take place before hard cost-data is available. And the authors of PURPA make it clear that they expect results soon.

CHAPTER VII

FAULT ANALYSIS TECHNIQUES

General Discussion

People associated with electrical transmission and distribution systems today have a distinct advantage over their counterparts of only a decade ago. They have computer systems which have matured significantly over those of that time, and software which has been developed to a startling degree. This particular tool, the computer, has added more versatility to power system fault analysis than would have been thought possible a decade in the past.

It is currently possible (and common) for the person evaluating a distribution system for fault currents to merely "model" the system (feed the computer all pertinent information on system components, conductors, characteristics, current sources and loads) and then to command the computer to calculate voltage profiles or current flows with short circuits imposed at any point in the system. With a few taps on the keyboard, he can change conductors or components, vary voltages, or add more lines or busses. More importantly, for our purposes, he can incorporate a new power source into the system and evaluate its

impact in the event of a fault.

Such computation systems range from primitive to sophisticated. Small, rural utility companies may not possess their own capability for modeling and evaluating those feeders with a potential for multiple power sources. Should a qualifying facility require interconnection, these utilities may need to seek assistance from consultation firms, academia, or utilities large enough to have justified the expense of the more expensive computation systems. The key point, however, is that such systems do exist, and are available to assess the impact of DES incorporation.

Although there are a number of software packages available for application to electrical systems, only one will be addressed herein. The package selected has many features in common with other of the more sophisticated programs, and other features uniquely its own. It is called the Distribution System Analysis Package, or DSAP, and a good deal of the following information is extracted from the DSAP operating manual.

Distribution System Analysis Package

In 1967, an early Fault Analysis program was written for Northeast Utilities. It was called the "Batch Radial Distribution Feeder Design Program" and was written by Chao Shu Chi of Northeast Utilities. DSAP is an outgrowth of that program. DSAP operates on the company's IBM 370/3033 TSO (Time Sharing Option) network and is interactive. Therefore, it allows a user to cre-

ate, modify and analyze radial distribution circuits on-line.

Many other computer programs use single phase analysis. Single phase loads are treated as balanced three phase loads modified by some conversion factor. This works well only when the system being analyzed is nominally balanced. DSAP, on the other hand, performs with unbalanced systems and single-phase loads. It is a radial distribution feeder analysis program consisting of a series of subroutines designed to calculate short circuits, flicker, load flow, voltage profile, system loss and capacitor and/or regulator economics.

Northeast Utilities advertises DSAP as having the salient features illustrated in Figure 6. It may be seen that the program is extremely versatile and adaptable. An important feature of the program, where utilities are concerned, is the ability to "grow" the electrical system. This subroutine allows the input of a growth rate (in percent per year), and a number of years for evaluation, and outputs a voltage profile at maturity. The advantages of this feature for planning purposes are easily seen.

The actual construction of the electrical model within the computer is performed by the DSAP program using the circuit data supplied by the user. The circuits can be stored on a direct access device, and therefore be subject to easy retrieval and modification from a remote terminal. DSAP is written with a large capacity and can accomodate 2,000 nodes (or busses), 1,000 transformers, and a capacitor at any or all nodes. It contains its own programmable conductor list with each conductor's impe-

1. Accurate answers are assured for an unbalanced as well as a balanced system.

2. All loads are simulated corresponding to their actual physical connections. No assumptions are needed to handle either a single phase or a three phase load.

3. The program is able to calculate voltage drops when two loads (any combination of a single or three phase) at different locations are suddenly applied simultaneously.

4. Voltage and current magnitude for each phase (A, B, C) of a node (bus) along the studied feeder will be calculated and printed. This gives a good indication of the effects of any unbalanced loading.

5. Warning messages are provided when a line or a transformer is thermally overloaded. The program is also capable of replacing the existing conductor with the next economically sized conductor when a prescribed current limit is exceeded.

6. Provision has been made to run a series of future years referring to a base case and analysing the system.

7. The automatic reconstruction of the circuit if the configuration is altered by adding or deleting elements.

8. The fault current calculations for three-phase, phase-to-phase, and phase-to-ground faults.

9. The ability to perform analysis for capacitor planning by adding, modifying or deleting capacitors easily.

Figure 6. Salient Features of DSAP Package.

Source: Northeast Utilities

dance and current-carrying characteristics, and a user need only enter a conductor code (up to 120) when building the model electrical system. DSAP will locate the appropriate characteristics to be used for computation. DSAP has the same (preprogrammed list) capability for up to 40 transformer types.

Execution

DSAP is "user-friendly". After calling up and entering the program, a user has a simple list of commands (see Figure 7) with which to construct electrical systems and perform various analyses. The commands fall into seven categories. The first category is administrative and has to do with loading a previously constructed model electrical system file, modifying or initiating titles, or emplacing a comment. The second category is concerned with adding, deleting, or changing data having to do with the system impedance characteristics. This category contains the controlling commands for the conductor list and the transformer list. The third category concerns itself with the conductors, or lines, in a system. Conductors may be added, deleted or changed between any two nodes in the system. An additional command (LSTL) will cause every line in the system, along with its characteristics, length and any integral transformers, to be displayed.

The fourth category of commands in DSAP gives the user the ability to imbed the characteristics and location of a fault in his model via a fault impedence table. The fifth category

```
TITL -- ENTERS NEW OR CHANGES A THREE-LINE TITLE
CMNT -- WRITES THE COMMENT ENTERED TO PAPER
LOAD -- LOADS A CIRCUIT HISTORY FILE FROM DISK

INTI -- LOAD INITIAL DATA INTO THE CODED IMPEDANCE DATA
ADDI -- ADDS AN ENTRY TO THE CODED IMPEDANCE DATA
DELI -- DELETES AN ENTRY FROM THE CODED IMPEDANCE DATA
CHGI -- CHANGES AN ENTRY IN THE CODED IMPEDANCE DATA
LSTI -- LISTS ALL ENTRIES IN THE CODED IMPEDANCE TABLE
INTT -- LOAD INITIAL DATA INTO THE CODED TRANSFORMER IMPEDANCE TABLE
ADDT -- ADDS AN ENTRY TO THE CODED TRANSFORMER IMPEDANCE TABLE
DELT -- DELETES AN ENTRY FROM THE CODED TRANSFORMER IMPEDANCE TABLE

INTL -- LOAD INITIAL LINE DATA TO THE CIRCUIT
ADDL -- ADDS A LINE TO A CIRCUIT
DELL -- DELETES A LINE FROM THE CIRCUIT
CHGL -- CHANGES THE CHARACTERISTICS OF A LINE IN THE CIRCUIT
LSTL -- LISTS CHARACTERISTICS OF ALL LINES IN THE CIRCUIT

INTF -- LOAD INITIAL DATA INTO THE FAULT IMPEDANCE TABLE
ADDF -- ADDS AN ENTRY TO THE FAULT IMPEDANCE TABLE
DELF -- DELETES AN ENTRY FROM THE FAULT IMPEDANCE TABLE
CHGF -- CHANGES AN ENTRY IN THE FAULT IMPEDANCE TABLE
LSTF -- LISTS ENTRIES IN THE FAULT IMPEDANCE TABLE

CNST -- CHANGES VALUES FOR MAXIMUM AND MINIMUM VOLTAGES
SOLU -- ENTERS SOLUTION AREA OF PROGRAM
CAPP -- CAPACITOR PLANNING - CAN ENTER THRU SOLU
SAVE -- SAVE THE CURRENT CIRCUIT TO DISK
EXIT -- EXIT DSAP

CHGT -- CHANGES AN ENTRY IN THE CODED TRANSFORMER IMPEDANCE TABLE
LSTT -- LISTS ALL ENTRIES IN THE CODED TRANSFORMER IMPEDANCE TABLE
LIMI -- SETS CONDUCTOR LIMITS TO SUMMER OR WINTER RATINGS

INTN -- LOAD INITIAL NODE DATA FOR THE CIRCUIT
ADDN -- ADDS A NODE TO THE CIRCUIT
DELN -- DELETES A NODE IN THE CIRCUIT
CHGN -- CHANGES THE CHARACTERISTICS OF A NODE IN THE CIRCUIT
LSTN -- LISTS CHARACTERISTICS OF ALL NODES IN THE CIRCUIT
```

Figure 7: Commands in DSAP
Source: Northeast Utilities

directs program control: is the user ready to have fault calculations performed? Is load-growth desired? Or a voltage profile? Should this model be saved for future reference? Is the user finished with calculations and ready to leave DSAP?

The sixth category is principally concerned with controlling transformer characteristics. The seventh, and last, category controls the addition, deletion, or change of characteristics of a node (or bus) and has the ability to display a list of all nodes in the system model.

These commands are minimal, yet versatile. Further, DSAP itself is written with ease of use in mind. It queries the user specifically on inputs and prompts the user during key operations. It will handle systems with three phases, one with loads across any two phases, one with loads from any phase to ground, or any combination thereof. It will calculate line losses and power factor at every node. It handles both real and imaginary (R+jX) impedances, currents and voltages. And it will calculate the voltage drop at every node due to a sudden load (motor start) at any node.

DSAP has many other features (such as capacitor planning) but it is not the purpose of this paper to expound on the virtues of one particular package as applied to the problems encountered by the incorporation of cogeneration and small power production facilities under PURPA, except to point out that such packages are available. These packages are well-developed and appropriate and little modification will be necessary to apply

them to utility feeders impacted by DES.

Conclusion

DSAP is an excellent software package which has the capability of measuring the impact, on each utility feeder customer, of any size Dispersed Energy Source requesting interconnection with the utility. Little guesswork is included in the calculations upon which this measurement is based, so a significant amount of reassurance is available through the use of this program.

DSAP has no monopoly in the field of electrical distribution system fault analysis. Nor is it claimed to be typical of other such programs. It is merely the program selected to illustrate the applicability of computation systems to the questions raised by PURPA.

CHAPTER VIII

CONCLUSION

Institutional barriers, more than economics, have prevented Dispersed Energy Sources from making a larger impact on the United States electrical power generation capacity. The Public Utility Regulatory Policies Act attempts to remove some of these barriers by providing a potential market for small power producers, voiding many bureaucratic requirements, and subsidizing DES through tax incentives. Development of DES under PURPA is attractive to the government because it lends itself well to our national energy policy.

Public acceptance and enthusiastic support for PURPA is also a goal of the government. More interest in the public sector will eventually convert into more DES development. Wide publicity is given to the re-opening of dam sites, solar power use by industry, and any type of waste recovery. (An April 8 Sunday Supplement Associated Press laserphoto was headlined "Treasure Pumped Out" and showed a technician adjusting a valve on one of the 57 pipes at a methane recovery operation at a Blue Island, Illinois landfill. It noted that 2,000 barrels of oil a week are replaced by this gas and declared that there are 3,500

other landfills around the country "that could be producing such treasure.") This type of public relations, when coupled with the features of PURPA, is bound to obtain results.

One controversial aspect of PURPA is that it leaves many items to the individual States which should perhaps be standardized. Interconnect methods, protective devices, power quality and methods for determining buy-back rates are among these items. And although it is true that less government is good government, consistency among the States is highly desirable when dealing with such issues. This consistency is also important for planning purposes where potential DES investors are concerned.

Many states have responded to PURPA rapidly and effectively. Appendix B lists buy-back rates (some "experimental") established by 26 States. A wide range of draft and final rules on DES regulation has also taken place. Appendix C lists Georgia's regulations on this subject. The American Public Power Association[18] has also sought to establish some standardization through proposing a list of "Rights" and "Obligations" for both the DES and the utility. This list is included as Appendix D.

Connecting, or paralleling, several central utility generating plants to a power transmission and distribution grid provides an almost infinite source of power where Dispersed Energy Sources are concerned. Just one nuclear generator station is usually rated at 800 to 1,000 megawatts. And utility

grids in densely populated areas of the country will commonly have capacities far in excess of 3,000 megawatts. Thus, when comparing small power production facilities with electric utilities, it is justified to consider the utility to be an infinite bus.[20] This is a characteristic of utility feeders that needs to be established for the reasoning which will follow.

Stability is an aspect of electrical power systems that may be approached statistically. Utilities are correct in their assertion that a small perturbation can have an effect totally out of proportion to its magnitude on a power system being operated close to its limit. But a sub-purpose of PURPA is to raise that limit, even if only slightly, through auxiliary generation capacity, fueled by renewable resources. It is conceivable that the penetration of DES may eventually reach the point (on a localized section of the grid) where stability evaluations should be run. But the fractional percentage of impact currently in perspective does not justify such analyses except on a local, and obvious, basis.

Reliability is somewhat different. One of the principal concerns of the utilities is that DES power may not be either reliable OR predictable. For co-generation facilities, predictability may be possible. Perhaps also for hydropower. But wind and solar will not only be unpredictable but, when operating, will also be variable. Many methods for proposing buy-back rates have included an adjustment based on the

reliability of power from the DES. But this one issue is the one that makes it most difficult for a utility to plan power production with an integrated DES. If a utility must keep a "spinning reserve" ready to replace power lost by a DES, a much-diminished savings is realized. A DES with the ability to accurately schedule reliable power production will find much greater acceptance with utilities than one who can't.

Safety is another issue between utilities and DESs generated by PURPA. All parties agree to the need for safety, but it is a truism that total safety is relative to system cost. This results in different views of system safety being held by each party, depending on who pays and how much.

Research is needed on the effects of harmonics on power system performance. Potential developers of power generation systems which produce direct current need a quantity of data not currently available in order to make decisions regarding the wisdom of developing such a facility, the type of DC to AC conversion equipment to obtain, and possible difficulties that must be overcome. Standards must be set on acceptable levels of harmonics.

From the point of view of a DES developer, facility cost is an important factor in determining whether to activate a DES. And the cost of interconnection turns out to constitute, in many cases, a significant portion of that cost. Some of the electrical components which a developer must obtain are illustrated in Figures 8, 9, 10 and 11. These are possible

interconnection schemes for facilities of up to 1,000kilowatts and were prepared by Science Applications, Incorporated under contract to the Electric Power Research Institute.[15] It should be noted that these diagrams do not show the complete generator protection package usually recommended by manufacturers.

Figure 8 shows an interconnection for units less that 20 kilowatts. The DES owner may share a single-phase distribution transformer with other utility customers or the utility may require a dedicated transformer, adding protection but increasing cost.

Above 20 kilowatts, a dedicated transformer and three-phase connection are usually required and additional protection is needed to detect distribution primary ground faults. Two options are illustrated in this Figure 9.

In Figure 10, a pad-mounted distribution transformer replaces the pole-top transformer due to size requirements. Additional fault protection is also incorporated.

Figure 11 shows a synchronous generator or line-independent, self-commutated inverter installation in the 200-1,000 kilowatt range. Overcurrent relays with voltage restraint replace the overcurrent functions shown in Figure 10. A magnetic tape recorder is used to obtain demand profile data for billing.

Some manufacturers are developing low-cost, low maintenance protection packages for DES. Beckwith Electric has developed a relay using a programmable read-only memory (PROM)

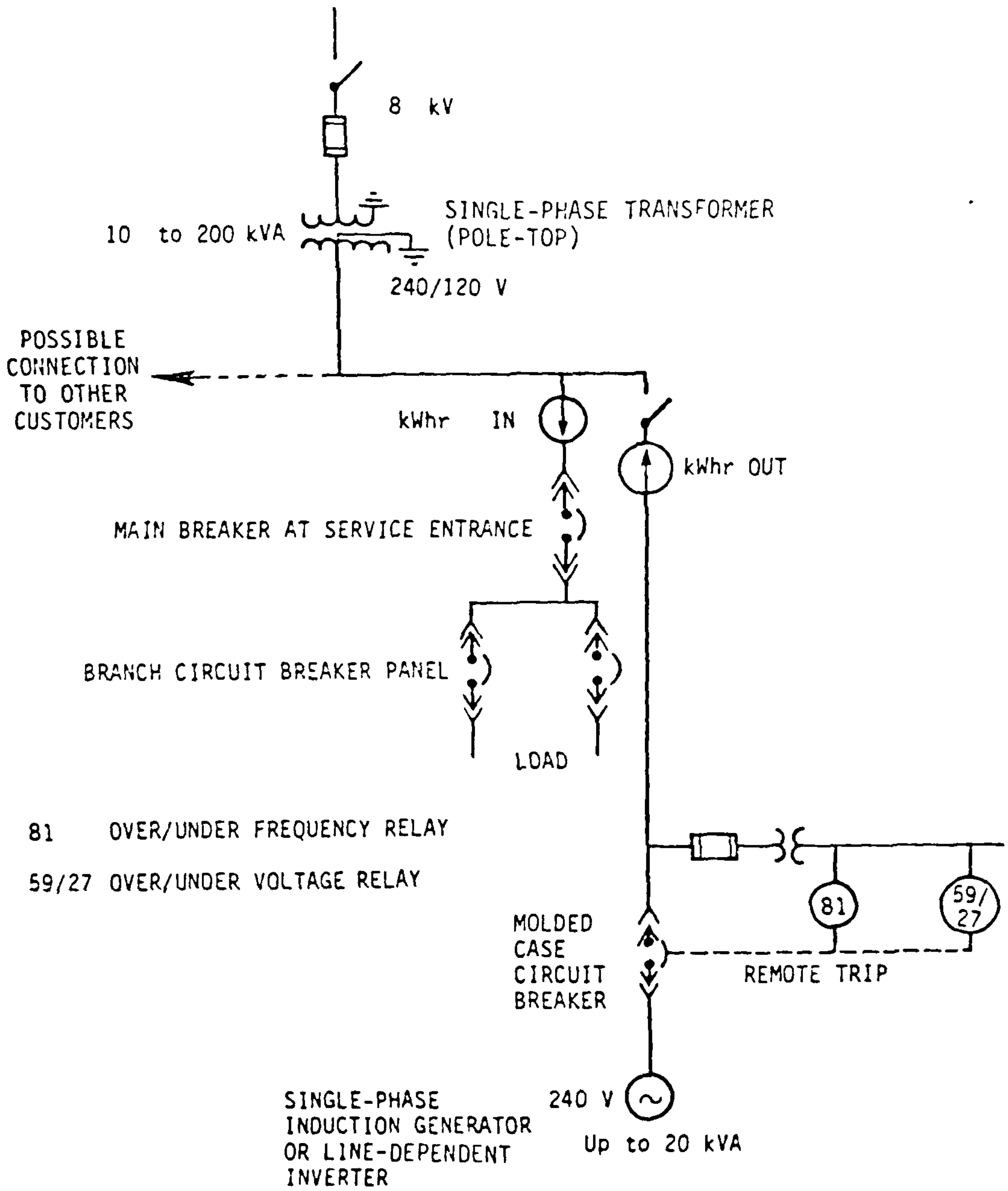


Figure 8. Scheme A: Interconnection Diagram for Line-Dependent DSPS up to 20 kVA

Source: Science Applications, Inc.

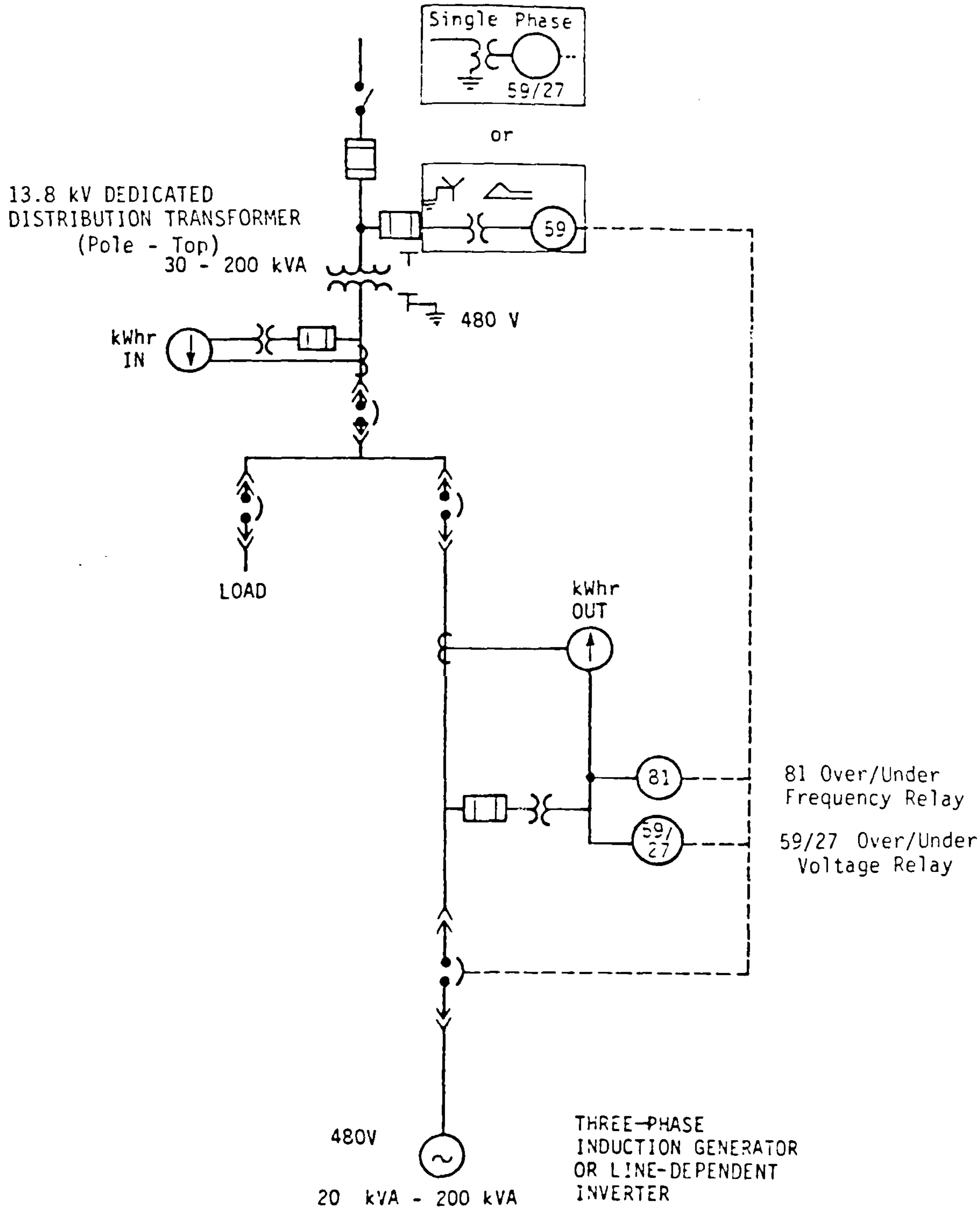


Figure 9. Scheme B: Interconnection Diagram for Line-Dependent DSPS Between 20 and 200 kVA

Source: Science Applications, Inc.

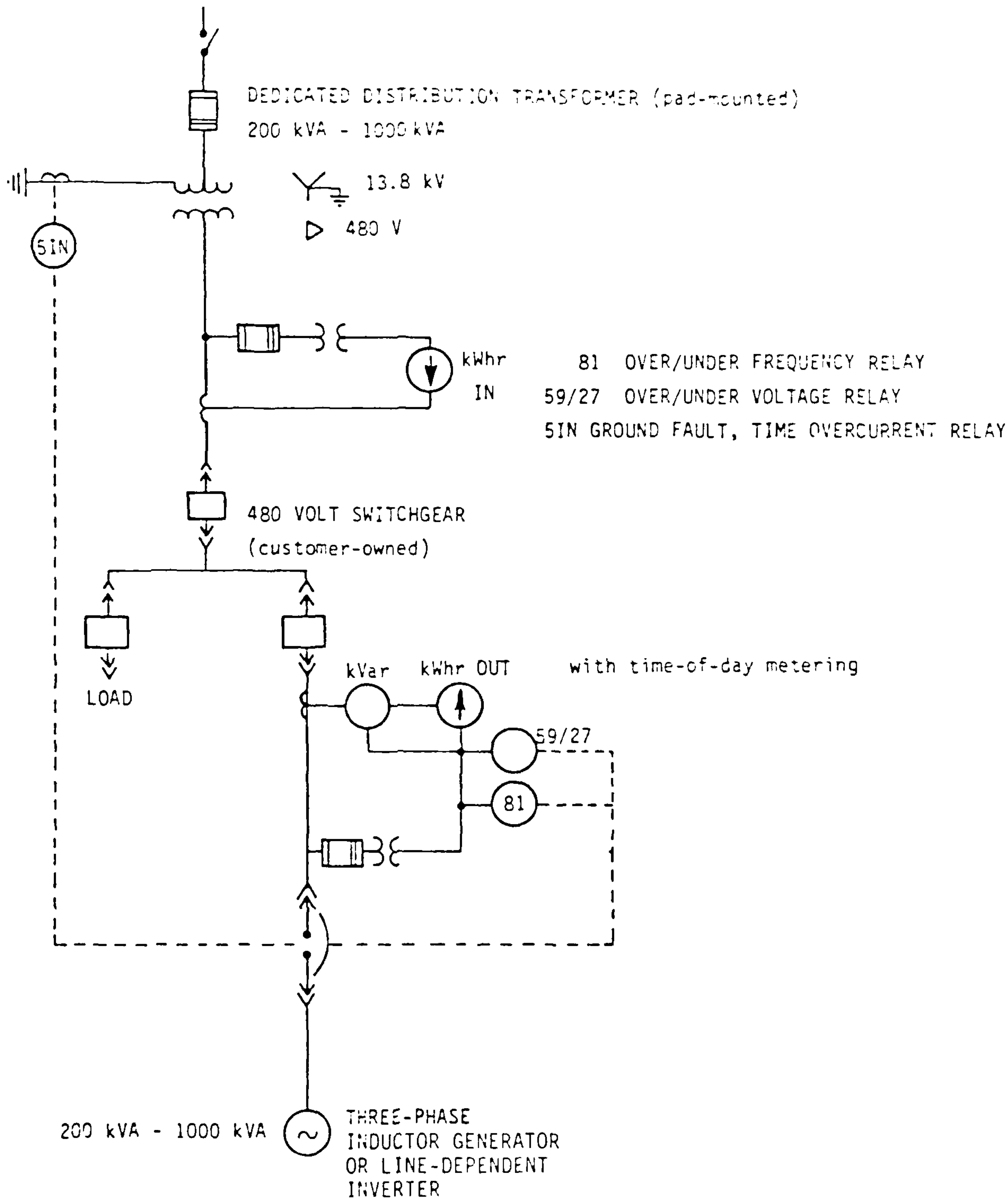
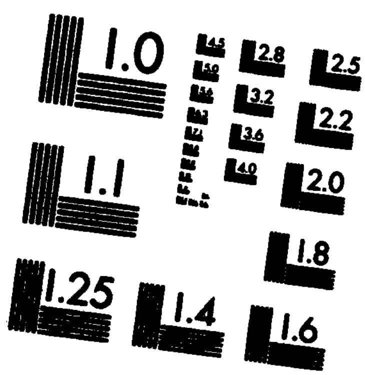


Figure 10. Scheme C: Interconnection Diagram for Line-Dependent DSPS between 200 and 1000 kVA

Source: Science Applications, Inc.

AD-A142 837 DISTRIBUTION SYSTEM STABILITY RELIABILITY AND PROTECTIVE RELAYING DUE TO..(U) AIR FORCE INST OF TECH WRIGHT-PATTERSON AFB OH K L ALLISON 1984 2/2

UNCLASSIFIED AFIT/CI/NR-84-24T F/G 10/2 NL



MICROCOPY RESOLUTION TEST CHART
NATIONAL BUREAU OF STANDARDS-1963-A

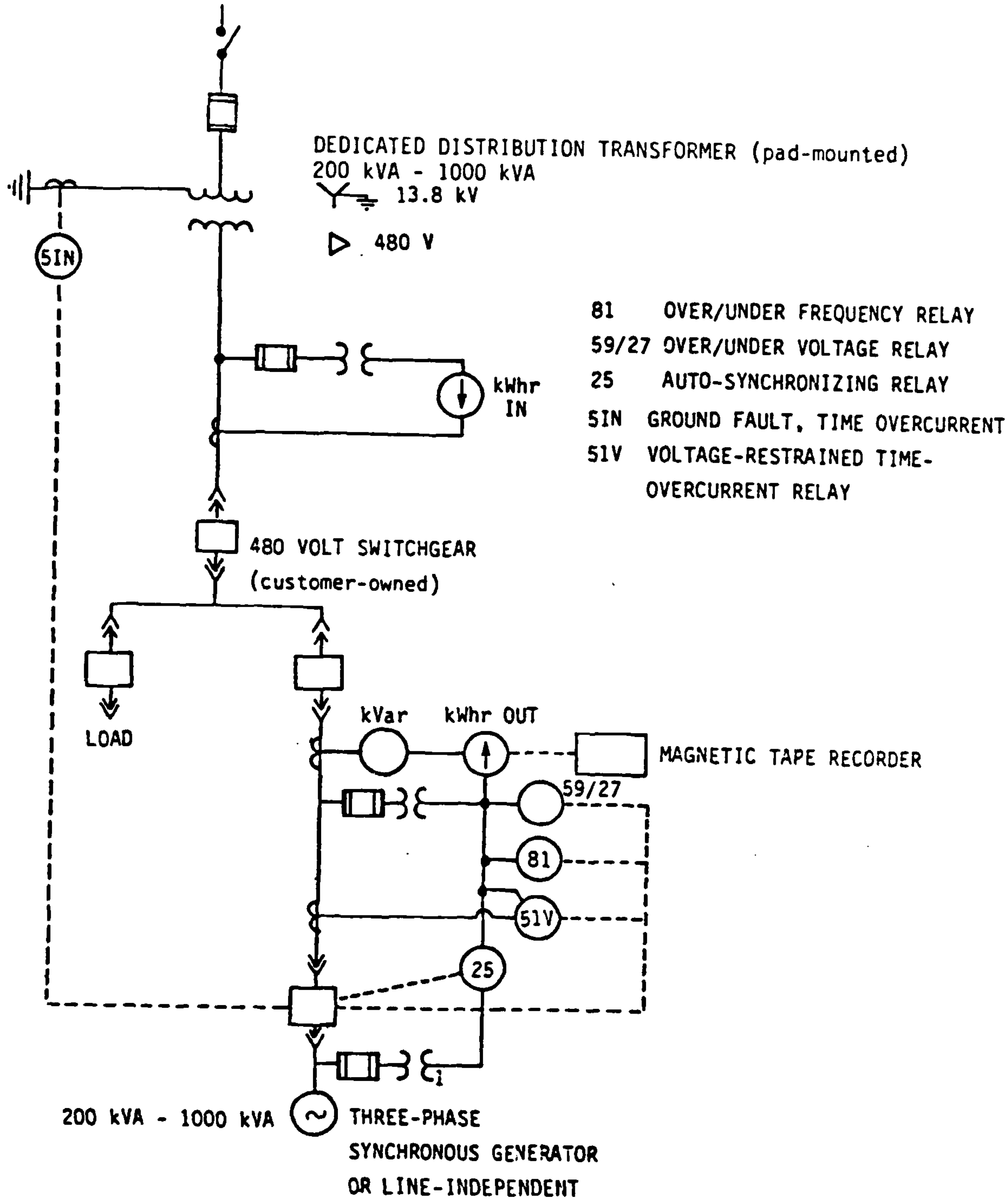


Figure 11. Scheme D: Interconnection Diagram for Line-Independent DSPS Between 200 and 1000 kVA

Source: Science Applications, Inc.

to detect abnormal frequency, voltage, and harmonic distortion. Wilmar Electronics and Basler Electric are developing protection packages using solid-state relays ordinarily used in industrial applications. Several other manufacturers are studying the potential market and utility inter-connection requirements before committing development resources.[15] As the technology for the interconnection and protection of DES matures and as the regulatory and utility requirements become defined, more competition should enter the field and component prices should decrease.

Wherever practical, Small Power Production facilities should be operated at low voltage (480Y/277 or 480D). This keeps switchgear and maintenance costs down. Air, metal-frame, and low-voltage breakers should be avoided because their switching endurance life is typically less than 25% of that of the newer insulated-case circuit breakers. Insulated-case breakers incorporate solid-state trip elements which provide a degree of flexibility to match virtually any over-current coordination protective scheme. Moreover, they typically cost less that metal-frame air breakers.[20]

In summary then, PURPA goes far in eliminating the institutional barriers that have plagued Dispersed Energy Sources in the past. Further, FERC applications over the preceding three years for qualifying status indicate the economic incentives for such endeavors have been recognized by potential developers. Remaining, however, is the resolution of several

technical and policy issues in order to get the PURPA program out of the developmental phase and into the operational phase.

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APPENDIX A

ACRONYMS AND ABBREVIATIONS

AC	- Alternating Current
BTU	- British Thermal Unit
DC	- Direct Current
DES	- Dispersed Energy Source
DSAP	- Distribution System Analysis Package
DSPS	- Distributed Solar Power Systems
EPRI	- Electrical Power Research Institute
FERC	- Federal Energy Regulatory Commission
KWH	- Kilowatt Hours
LOLP	- Loss of Load Probability
MRL	- Methane Recovery from Landfills
MSW	- Municipal Solid Wastes
OCB	- Oil Circuit Breaker
OCR	- Oil Circuit Recloser
PUC	- Public Utility Commission
PURPA	- Public Utility Regulatory Policies Act
QF	- Qualifying Facility
RMS	- Root Mean Square
SSH	- Small Scale Hydropower
VAR	- Volt-Ampere Reactive

APPENDIX B

STATE ELECTRICITY-BUYBACK RATES FOR QUALIFYING FACILITIES

(Source: Reiner H.J.H. Lock and Jack C. Van Kuiken,"Cogeneration and Small Power Production:State Implementation of Section 210 of PURPA," 3 Solar L Rep.659(November-December 1981).)

UTILITY	ENERGY PAYMENTS (¢/kWh)	COMMENTS
Alabama:		
Alabama Power Co.	2.59 on-peak, Jun-Oct 2.17 off-peak, " 2.14 on-peak, Nov-May 2.05 off-peak, "	Off-peak rates offered for utilities without time-of-day metering. Rates are for facilities less than 100kW.
Arkansas:		
Arkansas Power & Light	Reverse metering currently used.	
California:		
Pacific Gas & Electric	6.58 on-peak 6.219 mid-peak 5.553 off-peak 6.030 non-Tod	Rates are for 1981.
Southern Calif., Edison	6.6 on-peak 6.0 mid-peak 5.8 off-peak 6.0 non-TOD	
San Diego Gas & Electric	8.333 on-peak 7.069 mid-peak 6.225 off-peak 6.650 non-TOD	
Connecticut:		
Connecticut Light and Power & Hartford Electric Light	Firm Power 6.7 on-peak 5.4 off-peak Nonfirm Power 6.6 on-peak 5.2 off-peak	Rates tied to montnly fuel adjustment. Firm rates for DES over 100 kW.
Idaho:		
Utah Power & Light	Firm Power 1.2 Nonfirm Power 2.4	
Washington Water Power Co.	Firm Power 1.6 Nonfirm Power 2.4	
Idaho Power Co.	Firm Power 1.639	Facilities less than 100 kW.
Illinois:		
Illinois Power	2.42 on-peak summer 1.55 off-peak summer 2.65 on-peak winter 1.88 off-peak winter 1.89 Non-TOD summer 2.18 Non-TOD winter	
Commonwealth Edison	5.31 on-peak summer 2.90 off-peak summer	1,000 kW or less

UTILITY	ENERGY PAYMENTS (¢/kWh)	COMMENTS
Illinois (Cont'd)		
Commonwealth edison	3.37 off-peak winter	
Central Illinois Light Co.	34kV or greater:	
	2.3 on-peak	
	2.1 off-peak	
	12-34 kV:	
	2.4 on-peak	
	2.2 off-peak	
	Less than 12 kV:	
	2.5 on-peak	
	2.3 off-peak	
Interstate Power Co.	2.45 on-peak, Jun-Sep	
	2.05 off-peak, "	
	2.19 on-peak, Oct-May	
	2.05 off-peak, "	
Central Ill. Public Svc	1.978 on-peak, summer (3 mo)	
	1.620 off-peak, summer	
	1.884 on-peak, winter (3 mo)	
	1.661 off-peak, winter	
	1.805 on-peak, (rest of year)	
	1.565 off-peak	
South Beloit Water, Electric Co.	2.3 on-peak	
	1.7 off-peak	
Union Electric	1.77 summer non-TOD	
	1.53 winter non-TOD	
	TOD:	
	2.41 on-peak summer	
	1.36 off-peak summer	
	1.5 summer, weekends and holidays	
	1.86 on-peak winter	
	1.35 off-peak winter	
	1.35 winter, weekends and holidays	
Indiana:		
Indiana & Michigan Electric	1.36 on-peak TOD	
	0.81 off-peak TOD	
	0.81 non-TOD	
Indianapolis Power & Light	1.14 general rate	
	1.19 on-peak summer	
	1.07 off-peak summer	
	1.28 on-peak winter	
	1.08 off-peak winter	
Northern Indiana Public Svc	2.62 on-peak summer	
	2.29 off-peak summer	
	2.61 on-peak winter	
	2.29 off-peak winter	
	Non-TOD seasonal:	
	1.86 summer	
	1.83 winter	
Public Svc Co. of Ind.	1.33	
Southern Indiana Gas &	1.49 on-peak summer	

UTILITY	ENERGY PAYMENTS (¢/kWh)	COMMENTS
Indiana (cont'd)		
Elec.	1.02 off-peak summer 1.15 on-peak winter	
Southern Indiana Gas	1.00 off-peak winter	
Richmond Power & Light	0.914	
Kansas:		
Kansas Power & Light	1.6	
Massachusetts:		
Boston Edison	6.971 on-peak 4.047 off-peak 5.54 flat	
Commonwealth Electric	7.16 on-peak 6.15 off-peak 6.51 flat	Interim rates. Energy rates will be reset every 3 months when fuel adjustment is figured. QFs less than 30kW can use reverse metering.
Eastern Edison	6.792 on-peak 5.161 off-peak 5.995 flat	
Massachusetts Electric	5.51 on-peak 4.79 off-peak 5.08 flat	
Cambridge Electric	7.22 on-peak 5.91 off-peak 6.34 flat	
Nantucket Electric	7.44	
Manchester Electric	4.748	
Fitchburg Gas & Electric	6.081 on-peak 3.313 off-peak 4.940 flat	
Western Mass. Elec	5.813 on-peak 4.238 off-peak 4.979 flat	
Michigan:		
Consumers Power Co. and Detroit Edison	2.5	
Minnesota:		
Northern States Power Co.	Firm Power 2.06-3.07 increasing with contract length TOD metering service 2.15 on-peak 1.39 off-peak Nonfirm power 1.35 Occasional power 1.66	Temporary rate schedule.
Montana:		
Montana Power	2.7642	
Montana-Dakota	2.21 on-peak nonfirm	Nonfirm rates for

UTILITY	ENERGY PAYMENTS (¢/kWh)	COMMENTS
Montana (Cont'd)		
	1.57 off-peak nonfirm 1.91 nonfirm, non-TOD	QFs of 100 kW or less
Montana-Dakota	1.97-308 (depending on contract length)	
Pacific Power & Light	1.34-1.66	
Nebraska:		
Omaha Public Power District	TOD metering: 1.6 on-peak summer 1.0 off-peak all year 1.2 on-peak winter	
Nevada:		
Idaho Power	1.71 (Feb)- 4.16 (Aug)	
Sierra Pacific	4.09	
Nevada Power Co.	3.602 on-peak, Oct 81 1.943 off-peak, " 3.528 on-peak, Nov 81 2.331 off-peak, " 4.311 on-peak, Dec 81 2.630 off-peak, "	Rates vary monthly
New Hampshire:		
Statewide Rate	Firm power 8.2 Nonfirm power 7.7	Granite State Electric Utility not required to pay firm rate due to excess capacity
New Jersey:		
Jersey Central Power & Light	Approximate only: 6.0-7.5 on-peak 2.0-5.0 off-peak	
Atlantic City Elec Co.	2.5 Temporary rate	
New York:		
Statewide minimum rate	6.0	
North Carolina:		
Carolina Light & Power	2.80-5.55 on-peak 2.07-4.04 off-peak	Rates increase with contract length.
Duke Power Co.	2.38-5.20 on-peak 1.78-3.91 off-peak	"
Virginia Electric & Power	4.23-9.30 on-peak summer 3.59-4.30 peak nonsummer 2.62-5.77 all others	"
Nanthahala Power & Light	2.05	

UTILITY	ENERGY PAYMENTS (¢/kWh)	COMMENTS
North Dakota:		
Northern States Power Co.	2.15 on-peak 1.39 off-peak	Proposed rates for QFs less than 100 kW.
Oklahoma:		
Oklahoma Gas & Electric Co.	0.86-3.05 depending on firmness of capacity.	Formulas have been established to treat purchase rates for various types of QFs.
Oregon:	Reverse metering applies.	
Rhode Island:		
New England Power Co.	5.5247 on-peak 4.5339 off-peak 4.9843 average	
Blackstone Valley Electric Co.	Primary: 6.412 on-peak 4.842 off-peak 5.511 average Secondary: 6.726 on-peak 4.985 off-peak 5.723 average	
Newport Electric Co.	4.473 on-peak 4.093 off-peak 4.317 average	
South Carolina:		
Carolina Power & Light	2.80 on-peak 2.07 off-peak	Rates are for facilities less than 5 megawatts.
Duke Power Co.	1.98 on-peak 1.49 off-peak	
Utah:		
Utah Power & Light	2.2 (temporary)	
C.P. National	2.2 (temporary)	
Vermont:		
Statewide rate schedule	7.8 standard rate 9.0 on-peak TOD 6.6 off-peak TOD	
Wisconsin:		
Wisconsin Power & Light	1.80 on-peak 1.75 off-peak	QFs less than 200 kW.
Madison Gas & Electric	2.75 on-peak summer 1.50 off-peak " 2.22 on-peak winter 1.50 off-peak "	QFs less than 200 kW.
Wisconsin Electric Co.	3.65 on-peak summer firm	

UTILITY	ENERGY PAYMENTS (¢/kWh)	COMMENTS
Wisconsin (Cont'd)		
Wisconsin Electric Co.	1.45 off-peak summer firm	
	3.45 on-peak winter firm	
	1.45 off-peak winter firm	
	2.90 on-peak nonfirm	
	1.45 off-peak nonfirm	
Northern States Power	1.81 on-peak	QFs 21-500kW Thru 85.
	1.14 off-peak	QFs 21-500kW Thru 85.
	1.81 on-peak	QFs less than 21kW
	1.14 off-peak	QFs less than 21kW.
	1.60 on-peak	QFs over 21kW after 85.
	1.14 off-peak	QFs over 21kW after 85.
Lake Superior Dist.Pwr	1.90	QFs 6-200kW.
Wisconsin Public Service	1.85 on-peak	
	1.32 off-peak	
Wyoming:		
Utah Power & Light	2.2 nonfirm	(Note: All Wyoming are experimental)
	2.6 firm	QFs less than 100 kW.
Cheyenne Light, Fuel and Power	0.53	
Tri-County Electric Association	1.07	Wholesale supply rates.
Montana-Dakota Utilities	0.405	

APPENDIX C

GEORGIA REGULATIONS FOR SMALL POWER PRODUCERS

(Source: The American Public Power Association)

APPENDIX

MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA

800 Peachtree Center — South Tower, 225 Peachtree Street, Atlanta, Georgia 30303

PARALLEL OPERATION OF CUSTOMER GENERATION

Effective: *February 18, 1980*

I. *Policy*

It is the policy of the Integrated Transmission System (ITS) members (power suppliers) to permit any customer to operate his generating equipment in parallel with the ITS whenever this can be done without adverse effects on the general public, or to the power supplier's equipment or personnel. Certain protective devices (relays, circuit breakers, etc.), specified by the power supplier, must be installed at any location where a customer desires to operate generation in parallel with ITS. The purpose of these devices is to promptly remove the infeed from the customer's generation whenever a fault occurs, so as to protect the general public and the ITS facilities and personnel from damage due to fault currents produced by the customer's generator(s).

All customer generators larger than 10-kVA must be three-phase generators connected to three-phase circuits. Single-phase generators less than 10-kVA may be connected in parallel with the power supplier's system. These installations will be bound to the same general requirements as three-phase installations.

The power supplier will not assume any responsibility for protection of the customer's generator(s), or of any other portion of the customer's electrical equipment. The customer is fully responsible for protecting his equipment in such a manner that faults or other distrubances on the ITS or the power supplier's system do not cause damage to the customer's equipment.

II. *Objectives of this Procedure*

This procedure states the *minimum* requirements to be followed by ITS members for safe and effective operation of a customer intertie.

III. *General Requirements*

(1) The protective devices (relays, circuit breakers, etc.) required to promptly remove the fault contribution from the customer's generation should be owned, operated and maintained by the power supplier. In those cases where power supplier ownership is not practical, the protective equipment may be owned by the customer. In these instances, however, the following stipulations will apply:

(a) All protective devices installed to protect the power supplier's system from customer infeed will be specified by the power supplier.

(b) The installation and check-out devices must be supervised by the power supplier and subject to the power supplier's approval.

(c) All relay settings on the intertie will be specified by the power supplier.

(d) The power supplier reserves the right to inspect on demand all protective equipment including relays, circuit breakers, etc., at the intertie location. Inspection may include the tripping of the tie breaker by the protective relays.

The customer has full responsibility for the routine maintenance of his generating and protective equipment. The customer is encouraged to contract with the power supplier for routine maintenance of his protective equipment. Complete maintenance records must be maintained by the customer and be available for the power supplier's review.

The failure of the customer to provide proper routine maintenance will result in the customer being required to open his generator circuit breaker and cease parallel operation.

(e) Switching of the main tie circuit breaker must be under the operating direction of the power supplier, who reserves the right to open the disconnecting device with prior notice to the customer for any of the following reasons:

1 - System emergency.

2 - Inspection of customer's generating equipment and protective equipment reveals a hazardous condition, a lack of scheduled maintenance, or a lack of maintenance records.

3 - The customer's generating equipment interferes with other customers or with the operation of the ITS or power supplier's system.

(2) The customer should be advised that certain conditions on the ITS system may cause negative sequence currents to flow in the customer's generator. It is not the responsibility of the power supplier to protect the customer's equipment from existing negative sequence currents.

(3) No fuses or single-phase or three-phase automatic line switching devices, such as oil circuit reclosers, should be installed between the source substation and the customer substation. Single-phase or three phase sectionalizing equipment may be installed on the main circuit past the customer substation or on radial circuits that tap the main circuit between the source substation and the customer substation.
(See Figures 3, 4A, 4B, and 6 for examples of source and customer substations.)

(4) Except in unusual instances, customer's generation will not be connected in parallel with the ITS through power transformers protected by high-side fuses. This policy is intended to reduce the possibility of damage to the customer's machines due to negative-sequence currents.

(5) On radial transmission, substation and distribution circuits, a potential transformer and voltage check scheme must be installed on the source substation feeder breaker. This scheme will be designed to inhibit manual and

automatic reclosing to a hot line, so that the intertie cannot be accidently re-established (after a bus differential, for example) with the customer's generator(s) out of phase with the power supplier. Thus, if customer generation remains connected to an isolated, unfaulted line, it will be necessary to request the customer to manually trip his machine, so that the source substation breaker can be reclosed, and the circuit reconnected to the supply bus. If a customer can be connected to more than one power supplier's circuit, the voltage-check scheme must be installed on the alternate circuit(s), as well as the primary feed.

(6) The interconnection of the customer's generating equipment with the ITS or the electric system of an ITS member shall not cause any reduction in the quality of service being provided to other customers, with no abnormal voltages, frequencies, or interruptions being permitted. The power supplier will be the sole judge of what protective relays, circuit breakers, etc., will be installed to establish a safe and proper interconnection.

(7) Except in rare instances, to be determined by the power supplier, all customer generators shall be isolated from power supplier-owned equipment by a power transformer. This transformer must be connected in such a manner as to isolate the zero-sequence circuit of the customer's generator from the zero-sequence network of the utility. The power supplier will decide whether this power transformer shall be delta-connected, wye-connected solidly grounded, grounded through an impedance, or ungrounded at the interconnection line voltage.

(8) The customer will be solely responsible for properly synchronizing his generator(s) with the utility.

(9) The customer will not be permitted to energize a power supplier's dead circuit.

(10) The power supplier may require that a communication channel be installed as part of the relay protection scheme. This channel may be a leased telephone circuit, power line carrier, power supplier-owned pilot wire circuit, microwave, or other means to be determined by the power supplier.

(11) Any protective relaying changes or properties of the ITS members that may be required by interconnection with the customer's generator(s) will be considered part of the equipment required to accommodate parallel generation.

(12) Direct current generators may be operated in parallel with the ITS through a synchronous inverter. The inverter installation will be designed such that a utility system interruption will result in the removal of the inverter infeed to the utility. Harmonics generated by a D-C generator-inverter combination must not cause any reduction in the quality of service provided to other utility customers.

(13) If the power supplier is requested to do work on the customer's premises, an inspection of the work area will be made by the power supplier's operating personnel. If hazardous working conditions are detected, the customer will be required to correct the unsafe condition before the power supplier will perform the requested work.

(14) Increased fault current or levels or special conditions caused by the customer's generator(s) may require that equipment be installed or replaced on the ITS system. These equipment changes will be performed as part of the parallel generation intertie.

IV. *Classification of Installations with Customer Generation*

The following general classifications indicate the major operating characterists and protection requirements for typical installations. These classifications are determined in part by the electrical size of the customer generation. A large generator is defined as any generator 5 MW or larger. All other three-phase gnerators are considered small.

The increased degree of protection required for installation with over 5 MW of generation is due to increased short circuit contributions from larger units and increased investment by the power supplier in substation equipment. The larger transformers and circuit breakers needed to serve the customer's load require more sensitive and faster protection schemes.

The table shown below indicates the important characteristics of the six types of installations. This table will direct the reader to the appropriate installation type. Each classification is reviewed individually in the following sections, which give a general overview of the types of parallel connections approved for service on the power supplier's system.

Type	Generator Size Less than 5 MW	Number of Phases	System Connection	Two Way Power Flow
1	No	3	Network Line	Yes
2	No	3	Network Bus	Yes
3	No	3	Radial Line	Yes
4	Yes	3	Radial Line	Yes
5	No	3	Network Line	No
6	Yes	3	Radial Line	No

(A) *Type 1 installation — Large Generator on Network Line*

(1) A Type 1 installation is connected to the bulk transmission system of lines rated 115 kV and above.

(2) This type of installation provides for the interchange of power in either direction as a normal operating mode.

(3) Figure 1 shows the major equipment and protective relaying required for Type 1 installations.

(a) If the customer chooses not to install PCB B, he will be provided with trip and close control of PCB A and the ability to block close of PCB A.

(b) Utility operating and maintenance control of PCB A is required to protect utility equipment and personnel. The proper functioning of the utility system and the safety of substation and line maintenance

personnel is dependent upon the correct operation of PCB A and the protective relaying scheme.

(4) The revenue metering for Type 1 installations may include two watthour meters with detents One meter will be connected to measure power supplied to the customer from the power supplier. A second meter may be installed to measure customer generated power supplied to the power supplier. The meter detents prevent operation of either meter in the reverse direction.

B *Type 2 Installations — Large Generator on a Network Bus*

(1) A Type 2 installation is connected to a 115 kV (or above) network bus on the bulk transmission system.

(2) This type of installation provides for the interchange of power in either direction as a normal operating mode.

(3) Figure 2 shows the major equipment and protective relaying required for Type 2 installations.

(a) If the customer chooses not to install PCB B, he will be provided with trip and close control of PCB A and the ability to block close of PCB A.

(b) Utility operating and maintenance control of PCB A is required to protect utility equipment and personnel. The proper functioning of the utility system and the safety of substation operating and maintenance personnel is dependent upon the correct operation of PCB A and the protective relaying scheme.

(4) The revenue metering for Type 2 installations may include two watthour meters with detents. One meter will be connected to measure power supplied to the customer from the power supplier. A second meter may be installed to measure customer generated power supplied to the power supplier. The meter detents prevent operation of either meter in the reverse direction.

C *Type 3 Installations — Large Generator on a Radial Line*

(1) A Type 3 installation is tapped on a radial line. This line has a single utility substation source.

(2) This type of installation provides for the interchange of power in either direction as a normal operating mode.

(3) Figure 3 shows the major equipment and protective relaying required for Type 3 installations.

(a) If the customer chooses not to install PCB B, he will be provided with trip and close control of PCB A and the ability to block close of PCB A.

(b) Utility operating and maintenance control of PCB A is required to

protect utility equipment and personnel. The proper functioning of the utility system and the safety of substation and line maintenance personnel is dependent upon the correct operation of PCB A and the protective relaying scheme.

(4) The revenue metering for Type 3 installations may include two watthour meters with detents. One meter will be connected to measure power supplied to the customer from the power supplier. A second meter may be installed to measure customer generated power supplied to the power supplier. The meter detents prevent operation of either meter in the reverse direction.

D *Type 4 Installations — Small Generator on a Radial Line*

(1) A Type 4 installation is connected to a radial circuit.

(2) This type of installation provides for the interchange of power in either direction as a normal operating mode.

(3) Figures 4A and 4B indicate two acceprable connections for this type of installation. Figure 4A shows a delta-delta transformer with a high-side circuit breaker. Figure 4B shows a fused delta-delta transformer with a low-side circuit breaker.

(4) The preferred scheme for Type 4 installations is shown in Figure 4A. The high-side circuit breaker (A) is a three-phase interrupting device which inhibits single-phasing of customer's generator. The high-side potential phasors and voltage relay connections are shown on the figure. If the customer chooses not to install PCB B, he will be provided with a trip and close control of PCB A and the ability to block close of PCB A.

(5) Figure 4B shows a fused delta-delta transformer with a low-side circuit breaker. Device 47 is applied to prevent damage to the customer's generator due to blown fuses on the high side of this bank; and the customer should be made aware that his generator is exposed to negative sequence currents with this type of connection. If the customer chooses not to install PCB B, he will be provided with trip and close control of PCB A and with the ability to block close of PCB A.

(6) These schemes may also be employed if the power transformer is connected grounded-wye on the low-voltage side. In this case, a current transformer should be installed in the bank neutral to supply current to a backup ground relay.

(7) The revenue metering for Type 4 installations may include two watthour meters with detents. One meter will be connected to measure power supplied to the customer from the power supplier. A second meter may be installed to measure customer generated power supplied to the power supplier. The meter detents prevent operation of either meter in the reverse direction.

(E) *Type 5 Installations — Large Generator on Network Line*

(1) A Type 5 installation may be used in any case where the customer's load greatly exceeds his generating capacity.

(2) This type installation does not allow the interchange of power from the customer to the utility.

(3) Figure 5 shows the major equipment and protective relaying required for Type 5 installations. Note that PCB A will be tripped by reverse power relay (32) if the customer generation exceeds the customer load. If PCB A is open, the customer bus must be de-energized before PCB A can be closed. The customer generation can then be synchronized and paralleled with the utility by closing PCB B.

(4) This type installation requires the standard single revenue meter installation.

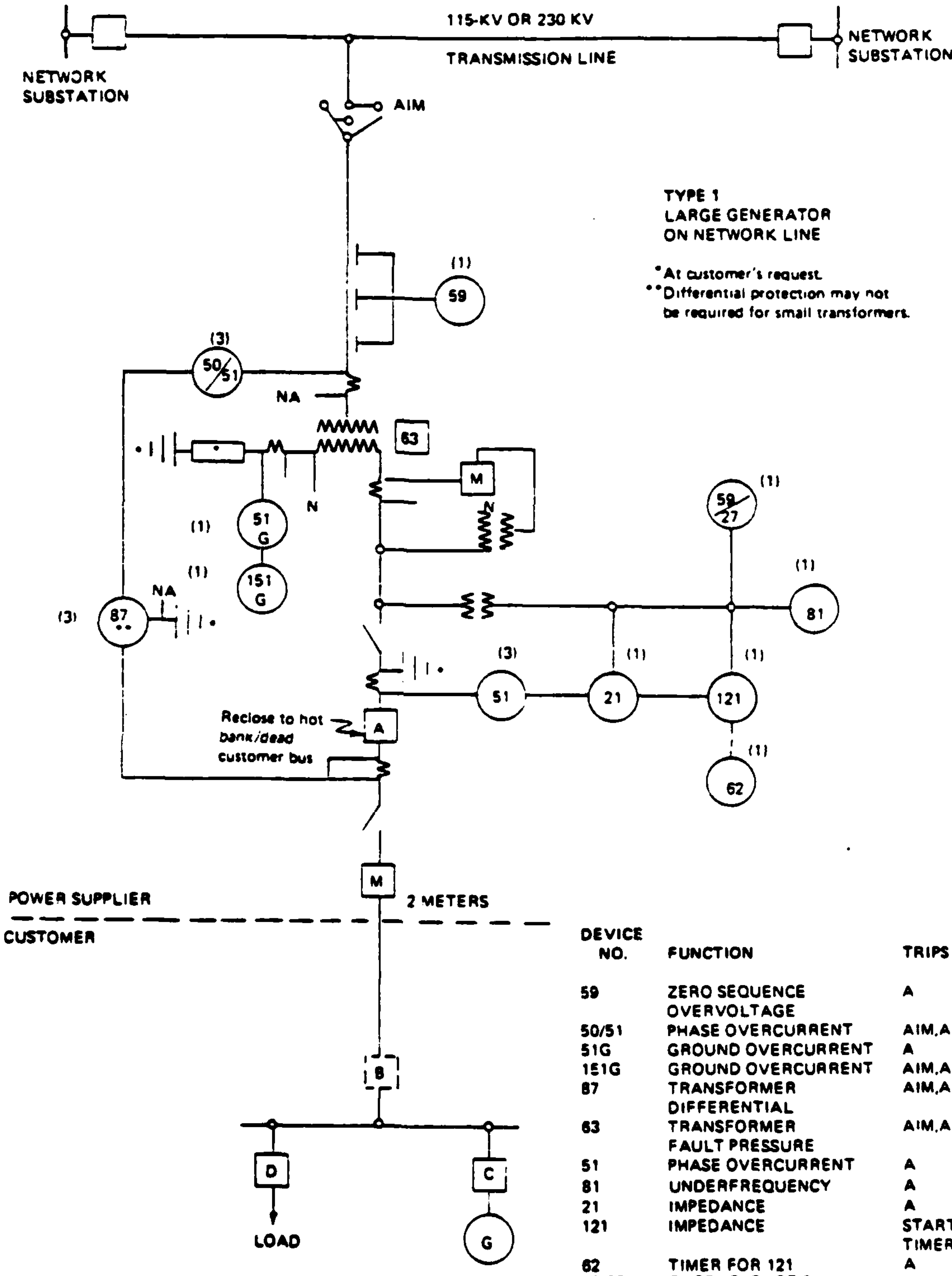
(F) *Type 6 Installations — Small Generator on Radial Line*

(1) A Type 6 installation may be used in any case where the customer's load greatly exceeds his generating capacity.

(2) This type installation does not allow the interchange of power from the customer to the utility.

(3) Figure 6 shows the major equipment and protective relaying required for Type 6 installations. Type 6 installations will only be allowed in those small substations where a high or low-side bank breaker is not practical. Note that the power supplier must have trip control over customer PCB A. Refer to Section III, Item (l), for a detailed description of installation, operating and testing requirements. The negative sequence relay, device 60Q operation indicates a single-phased condition requiring the tripping of both the generation and load. Reverse power relay (32) will trip PCB A if the customer generation exceeds the customer load.

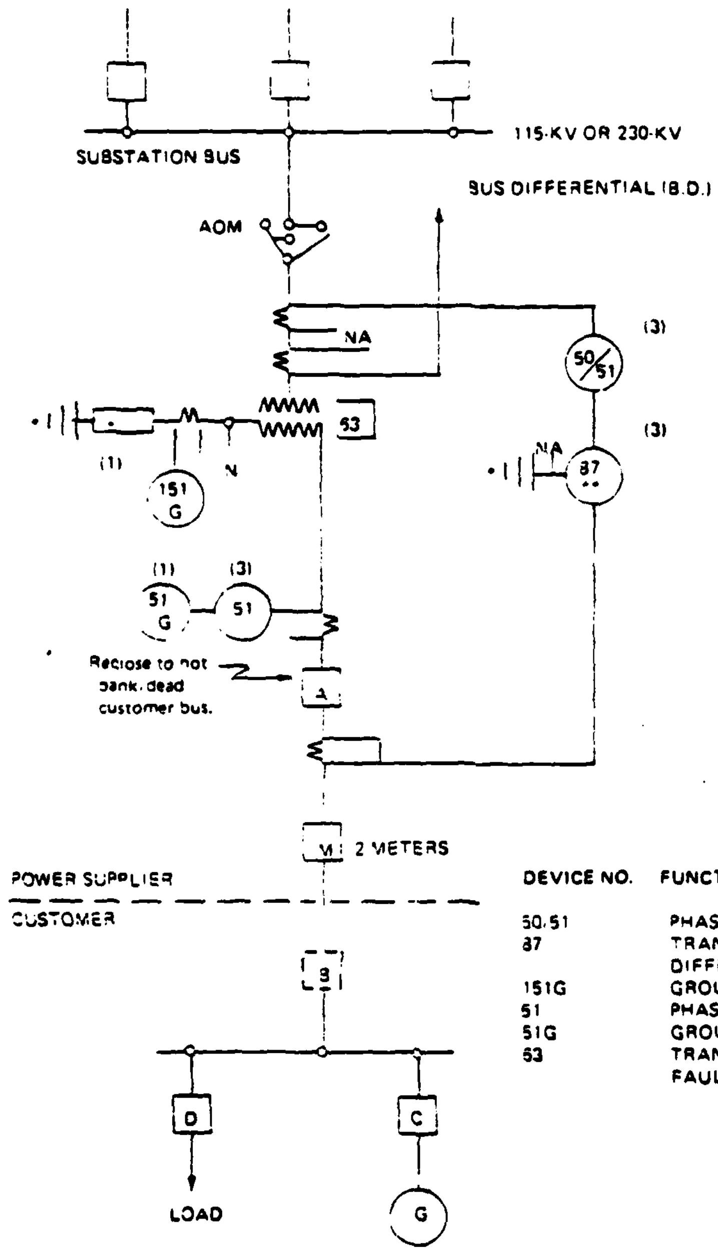
(4) This type of installation requires the standard single revenue metering installation.



DEVICE NO.	FUNCTION	TRIPS
59	ZERO SEQUENCE OVERVOLTAGE	A
50/51	PHASE OVERCURRENT	AIM,A
51G	GROUND OVERCURRENT	A
151G	GROUND OVERCURRENT	AIM,A
87	TRANSFORMER DIFFERENTIAL	AIM,A
63	TRANSFORMER FAULT PRESSURE	AIM,A
51	PHASE OVERCURRENT	A
81	UNDERFREQUENCY	A
21	IMPEDANCE	A
121	IMPEDANCE	STARTS TIMER 62
62	TIMER FOR 121	A
59/27	OVERVOLTAGE & UNDERVOLTAGE	A

FIGURE 1

2/15/80



TYPE 2
LARGE GENERATOR ON NETWORK BUS.

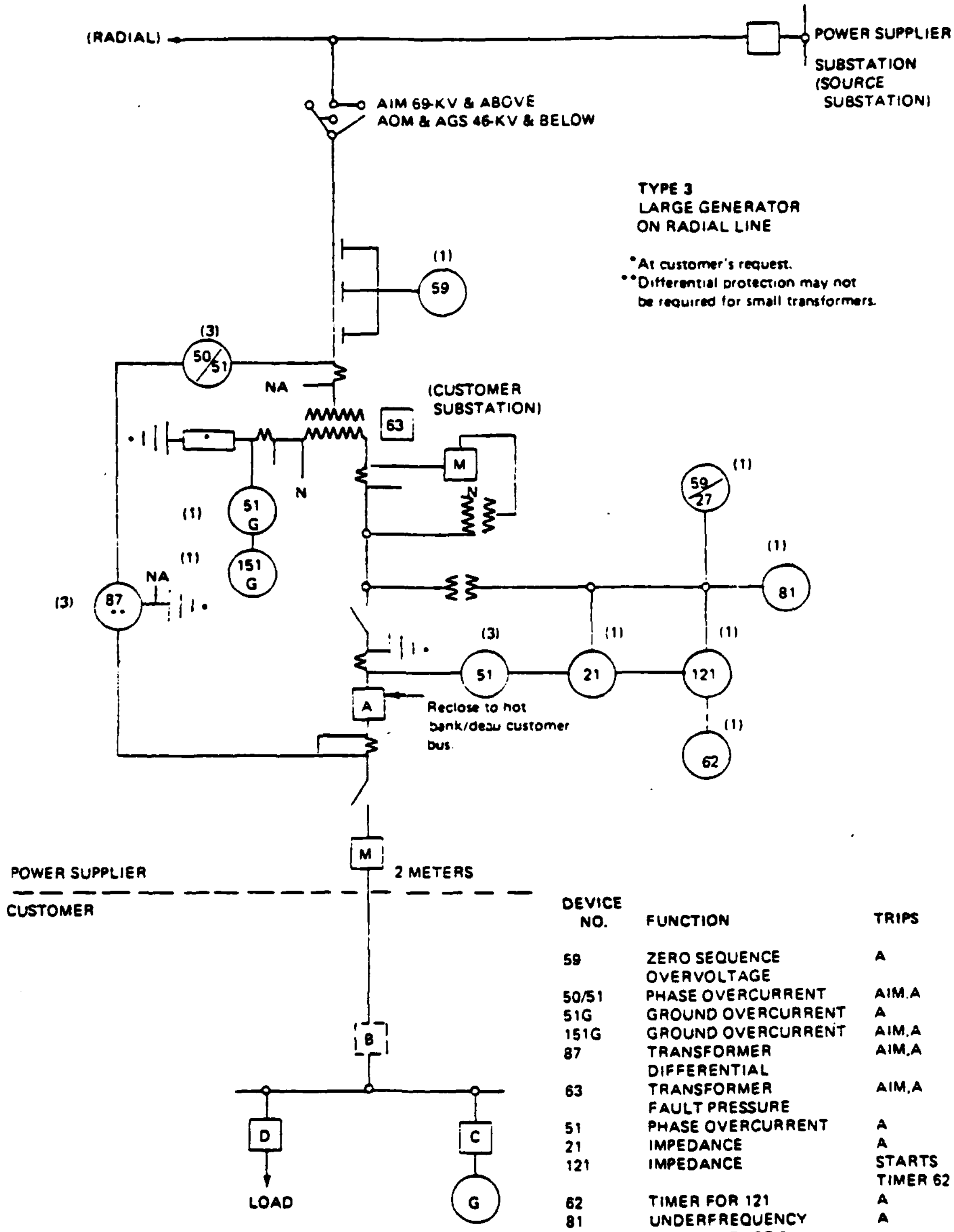
*At customer's request.

**Differential protection may not be required for small transformers.

DEVICE NO.	FUNCTION	TRIPS
50/51	PHASE OVERCURRENT	B.D., AOM, A
87	TRANSFORMER DIFFERENTIAL	B.D., AOM, A
151G	GROUND OVERCURRENT	B.D., AOM, A
51	PHASE OVERCURRENT	A
51G	GROUND OVERCURRENT	A
63	TRANSFORMER FAULT PRESSURE	B.D., AOM, A

FIGURE 2

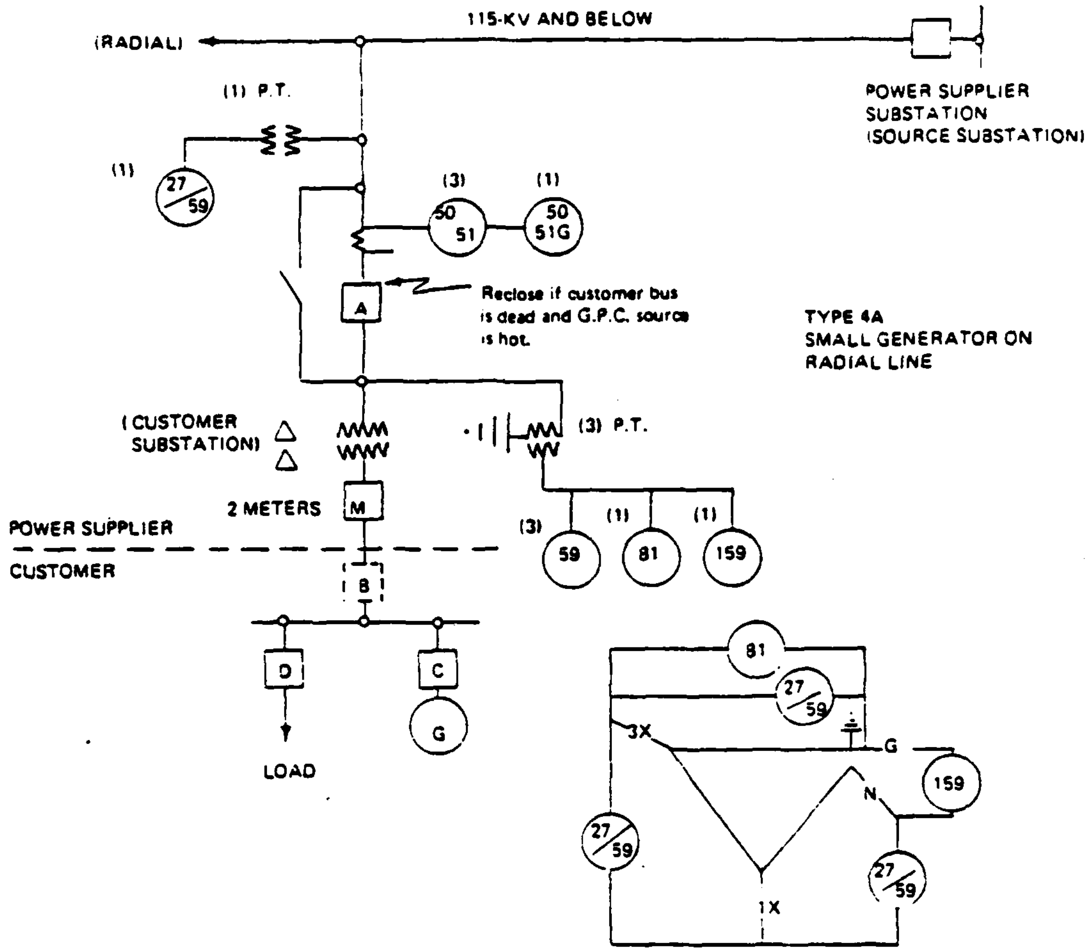
2/15/80



DEVICE NO.	FUNCTION	TRIPS
59	ZERO SEQUENCE OVERVOLTAGE	A
50/51	PHASE OVERCURRENT	AIM.A
51G	GROUND OVERCURRENT	A
151G	GROUND OVERCURRENT	AIM,A
87	TRANSFORMER DIFFERENTIAL	AIM,A
63	TRANSFORMER FAULT PRESSURE	AIM,A
51	PHASE OVERCURRENT	A
21	IMPEDANCE	A
121	IMPEDANCE	STARTS TIMER 62
62	TIMER FOR 121	A
81	UNDERFREQUENCY	A
59/27	OVERVOLTAGE & UNDERVOLTAGE	A

FIGURE 3

2/15/80

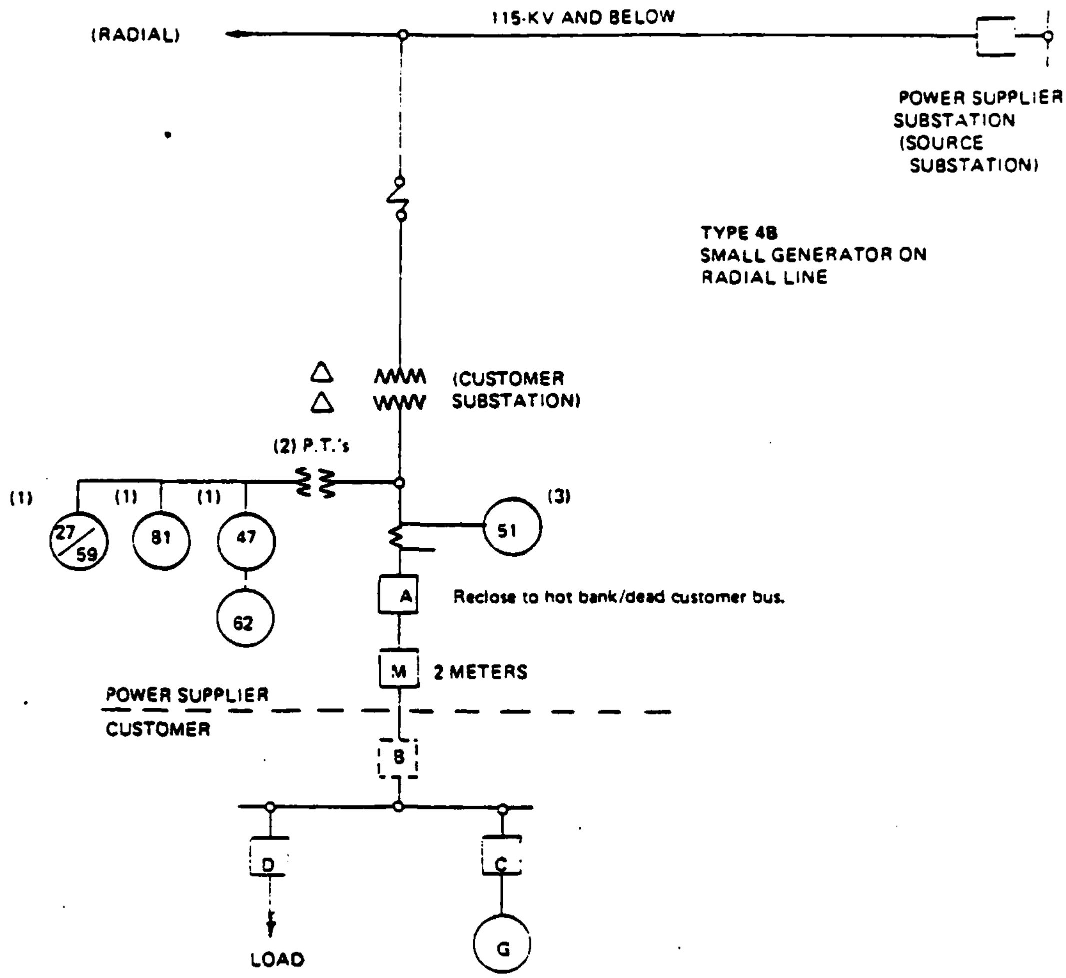


TYPE 4A
SMALL GENERATOR ON
RADIAL LINE

DEVICE NO.	FUNCTION	TRIPS
27/59	UNDER AND OVERVOLTAGE	A
50/51	PHASE OVERCURRENT	A
50/51G	GROUND OVERCURRENT	A
59	OVERVOLTAGE	A
81	UNDERFREQUENCY	A
159	ZERO SEQUENCE OVERVOLTAGE	A

FIGURE 4A

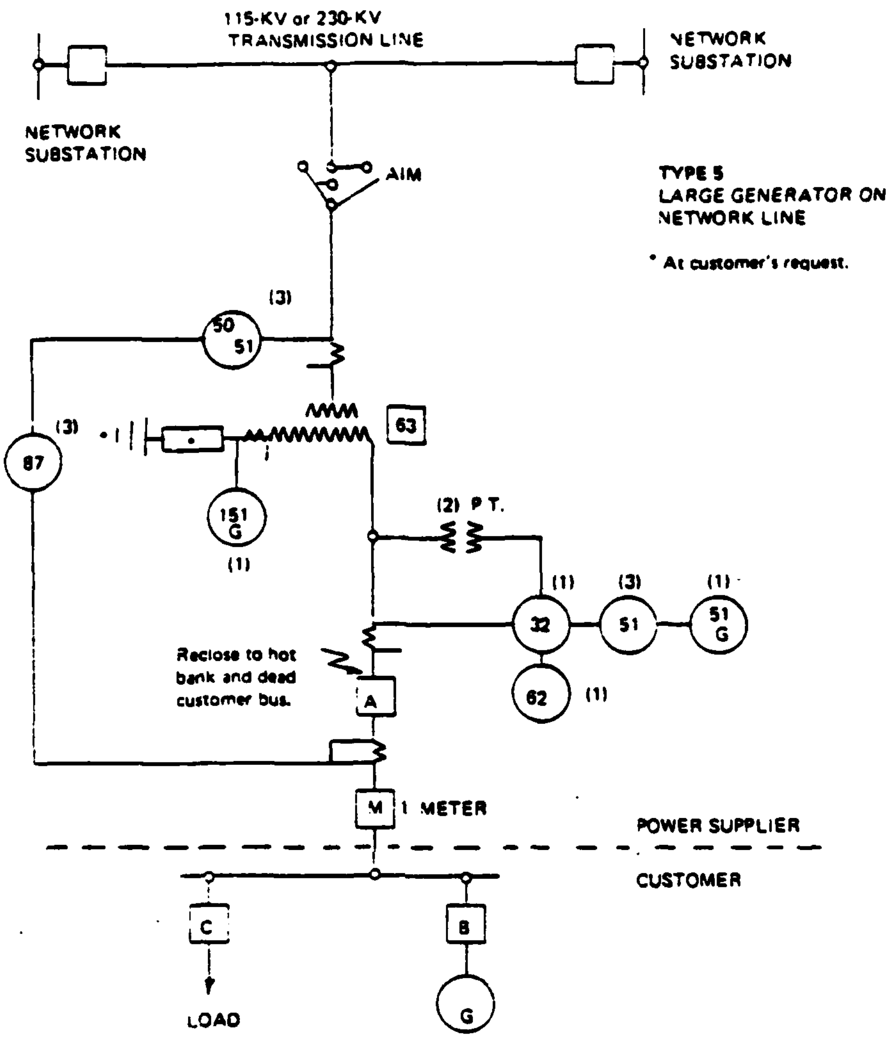
2/15/80



DEVICE NO.	FUNCTION	TRIPS
51	PHASE OVERCURRENT	A
47	NEGATIVE SEQUENCE VOLTAGE	STARTS TIMER 62
62	TIMER FOR 47	A
81	UNDERFREQUENCY	A
27/59	UNDER AND OVERVOLTAGE	A

FIGURE 4B

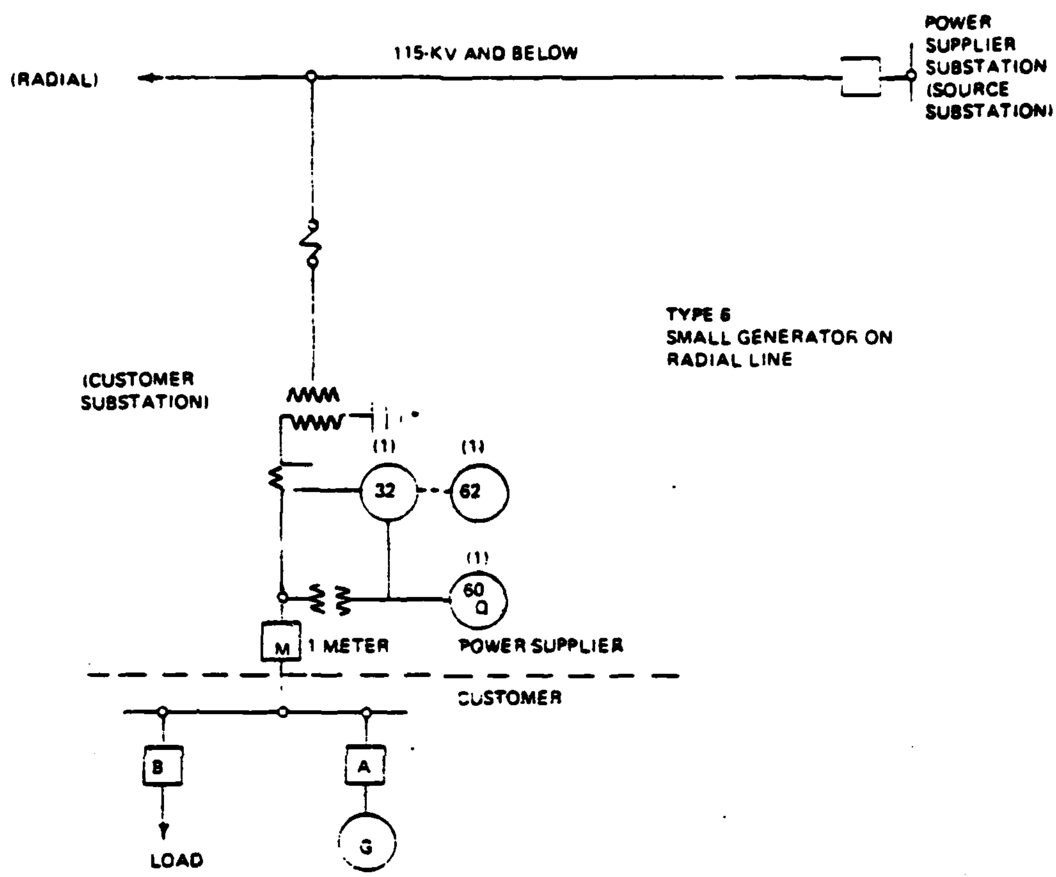
2/15/80



DEVICE NO.	FUNCTION	TRIPS
50/51	PHASE OVERCURRENT	AIM, A
87	TRANSFORMER DIFFERENTIAL	AIM, A
151G	GROUND OVERCURRENT	AIM, A
63	TRANSFORMER FAULT PRESSURE	AIM, A
32	REVERSE POWER	STARTS TIMER 62
62	TIMER FOR 32	A
51	PHASE OVERCURRENT	A
51G	GROUND OVERCURRENT	A

FIGURE 5

2/15/80



DEVICE NO.	FUNCTION	TRIPS
32	REVERSE POWER	STARTS TIMER 62
62	TIMER FOR 32	A
60Q	NEGATIVE SEQUENCE VOLTAGE	A,B.

FIGURE 6

2-15-80

APPENDIX D

PROPOSED RIGHTS AND OBLIGATIONS

FOR UTILITIES AND DISPERSED ENERGY SOURCES

(Source: The American Public Power Association)

RIGHTS AND OBLIGATIONS

A. *Ownership, Design, Operations & Maintenance*

UTILITY	CUSTOMER
	Construct, operate and maintain the following small power production facility (specifically described) to and at point of delivery (Plains)
	Design, construct, operate and maintain facility in accord with Prudent Utility Practice (LA)
May set reasonable requirements for facility and equipment	Design, construct, install, own, operate and maintain all *equipment required to generate* and deliver energy and/or capacity specified herein (except special facilities) — meet *reasonable* utility requirements for equipment . (PG&E)
Same responsibility up to point of connection with TVA	Except as otherwise provided — responsible for installing, owning operating *all* equipment to point of connection with distributor utility. (TVA)
	Provide all necessary equipment and facilities (required by applicable rate schedule) and all priv., easements, licenses, and other rights to enable utility to deliver, purchase and sell. (Plains)
	Own and maintain all facilities on customer side of point of delivery as specified by utility (except meters) (PP&L)
	Construct, install, own and maintain *interconnection* facilities. Size designated in agreement (PG&E)
Metering and protective equipment are property of utility. Utility has complete ownership and control of said facilities. (Texas)	
Design, construct, operate and maintain Company facility and modifications they deem necessary to interconnection (Standard = Prudent Utility Procedure) (LA)	
Construct and maintain facilities beyond Utility point of delivery. (Plains)	

UTILITY	CUSTOMER
Extend and maintain lines to premises of facility.	
Install transformer switches, lightning arrestors, meters, recording devices and other apparatus for delivering and measuring energy (includes sufficiency standard, e.g. maximum *capacity requirements*)	Must notify if significant change in capacity. (Goodland)
Provide separate metering on time of purchase basis for generator output and customer's usage.	
Give incentive (payment) for performance. (So. Cal. Ed.)	
Supply separate meters and detents (Prevent reverse rotation)	Supply meter sockets. (Grand Island)
	Install and maintain in good working order: (1) Generating equipment including line from facility to customer residence for AC power. (2) Required relaying and protective device which will automatically physically disconnect and will not automatically reconnect unless approved automatic phasing equipment is installed. (3) Operate facility at not less than 90% power factor. (Central Vermont)

Neither Party shall own or hold interest in facility required to be provided by the other. (Plains).

UTILITY	CUSTOMER
Right to designate equipment suitable to parallel operation.	Furnish, install, operate and maintain *specified* facilities designated by utility as suitable for parallel operation. Right to appeal conditions imposed by utility. (Wisconsin Power & Light)

Sample Provision

The customer shall furnish, install, operate and maintain facilities such as relays, switches, synchronizing equipment, control and protective devices designated by the Company as suitable for parallel operation with the Company system. Such facilities shall be accessible at all times to authorized Company

UTILITY	CUSTOMER

personnel. the customer retains the right to appeal to the Public Service Commission if conditions being imposed by the Company are perceived to be excessively stringent. (Wisconsin P&L)

B. Plans and Specifications

UTILITY	CUSTOMER
	Provide specifications for utility review (LA)
Right to approve equipment prior to installation or connection	Submit to utility schematic drawings and manufacturer's manual. Must have utility approval prior to installation and connection (OPPD).
	Submit proposed specifications of equipment to (TVA) for written approval prior to connection (TVA).
Right to *review* specifications.	Submit all equipment specifications to utility for review prior to connection (PG&E)
	Provide Utility with description of equipment to be installed and a schematic drawing of interconnection. Details of specifications set out in contract, of: tower, generator, inverter, interconnection details. Generator and inverter instruction manuals and specifications are to be provided. (Grand Island)
	Option to allow Company to make facility description available and public to evaluate performance (Grand Island)

C. Inspections and Tests

UTILITY	CUSTOMER
Right to inspect.	Install and maintain at customer expense all necessary facilities on its side of delivery point — not interfere with other service. (Goodland)
Right to: Inspect, conduct operating tests of protective devices, review all data collected from facility — at reasonalble times, independently monitor system.	

Sample Provision

The Company shall have the right to inspect the Customer's electric generating facilities,

UTILITY	CUSTOMER
to conduct such operating tests as are necessary to ascertain that the protective devices function properly; to review any data collected from such facilities at all reasonable time, and to independently monitor the aforesaid system (Central Vermont)	
Utility right to be present at test.	Notify prior to start up and testing of facility (Kansas P&L)
Right to be present at test.	Test equipment — give utility reasonable notice (L.A.)
Right to measure power factor at any time to verify customer operating within requirements (Eastern)	

D. Change of Equipment

UTILITY	CUSTOMER
	Change equipment as may reasonably be required to meet change in utility system (PG&E)
	Changes in equipment necessitated by change in service requirements to accommodate new conditions (Grand Island)
	Make and bear cost (except as otherwise provided) of changes in connection, protective, and control equipment necessary to meet changing conditions and requirements (TVA)
Right to change transformers and service voltage when necessary.	Change equipment per the agreement at its cost (OPPD)

E. Costs

UTILITY	CUSTOMER
	Pay on demand, specified amount, in consideration of agreement of utility to own and operate metering and protective equipment (Texas)
	Pay expenses of utility prior to installation (for installation and ownership of special equipment required to protect utility consumers and for expenses of startup) (OPPD)
	Facility shall reimburse within 20 days of billing for installation, operations, maintenance of additional connection,

UTILITY	CUSTOMER
	relaying, switching, metering, line and safety and other equipment and facilities requirements by Company to: Assure reliability, protect equipment and personnel, and protect other customers. (Plains)
	Reimburse utility (on demand) for expenses incurred due to installation and operation of facility (includes labor and materials) (Grand Island)
	Reimburse utility for costs of special facilities (defined by appendix) (PG&E)
	Reimburse for equipment and facility required for parallel generation (Kansas P&L) (Goodland)
	Pay all costs (including installation costs incurred by utility in changing its system as is agreed to be necessary to accommodate facility). (Easton)
Install, own and maintain disconnecting device near meter.	Shall install, operate and maintain without cost to Company — relays, locks and seals, breakers, automatic synchronizers and other control and protective apparatus. (Goodland)
Install, own, and maintain a disconnecting device — location specified — at all times accessible to utility personnel.	Furnish, install, operate and maintain in good order and repair — relays locks and seals, breakers, automatic synchronizer, and other apparatus suitable for parallel operation. (Kansas P&L)
Must approve specs, operating characteristics for facility and interconnection	Install, operate and maintain adequate safety and protective devices (approved by company) on producer's side of point of delivery.
	All facilities must meet NESC and other applicable safety standards.
	Must provide for immediate break of electric interconnection if voltage from company is absent. (Plains)

F. Control and Protective Apparatus

Right to install protective equipment necessary to protect own property. Not obligated for property of the other (TVA)

UTILITY	CUSTOMER
	Provide equipment to be capable of coordination with utility's. (TVA)
	Furnish own transforming and protective equipment, including *(detailed)*. Power factor and reactive rules may require voltage regulators and/or automatic transformers. No credit for facilities (Peabody)
	Maintain operating communications through company's sub — including shutdowns, equipment clearance and daily load reports. (PG&E)
Sole judgement as to necessity of additional equipment.	Reimburse utility in future for additional metering or protective equipment. (Texas)

G. Location

UTILITY	CUSTOMER
	Locate tower sufficiently away from utility lines to avoid tower falling or making contact with utility lines. (OPPD)
	Locate (SWECS) tower well away from utility lines and equipment. Comply with zoning and other codes and state building department approval (date and signature) (Grand Island)

H. Delivery and Amount of Production

UTILITY	CUSTOMER
	Deliver energy and/or capacity at points of conduction contact at transmission side of high voltage disconnect — or by other agreement. (PG&E)
	Must attain a stated minimum availability.
	Must attain a stated minimum capacity factor. Capacity payment reduced if below minimum. (So. Cal. Ed.)

May request new capacity rating for facility if reasonably apparent has changed. (PG&E)

UTILITY	CUSTOMER
May provide reactive power at customer's expense.	Operate and maintain facility according to prudent electrical practice and generate sufficient reactive power reasonably necessary to maintain voltage levels and reactive area support. (PG&E)

UTILITY	CUSTOMER
Purchase requirement Not required to purchase: 1. If less costly to generate or purchase = amount 2. Would contribute to system emergency 3. Breach of contract by consumer 4. Purchase raises risk of loss of property or injury 5. When systems are not operated in parallel. (Plains)	
Right to require	May be required to limit generating production to total of customer load (Goodland)
Right to require as conditions warrant to limit production to amount no greater than load at customer facility of which generation facility is a part. (Kansas P&L)	
Right of first refusal for excess generating capabilities (BPA)	

Provision details circumstances when company can require facility to curtail, interrupt or reduce delivery including: (1) operating conditions (2) lower cost power (3) minimization of air pollution (4) during periods of minimum system operation. (PG&E)

UTILITY	CUSTOMER
Provide generation control frequency control, undistorted wave form, reactive power and other functions (non-metered).	If concentration of SWECS exceeds utility ability to supply, non-metered quantities of electric power, customer will be responsible for such regardless of installation. (Grand Island)

Sample Provision

The customer understands that the main function of SWECS is to supply energy. The Utility must still provide generation control, frequency control, an undistorted wave form, reactive power, and other functions. the concentration of SWECS may eventually interfere with the ability of the electric system in supplying these non-metered quantities.

In the event that SWECS concentration exceeds the ability of the electric system to

UTILITY	CUSTOMER

supply such non-metered quantities, the customer shall be responsible for providing these quantities without regard to the original installation date of the SWECS. (Grand Island)

I. Notice

UTILITY	CUSTOMER
	Give notice at 3 month intervals of estimated date of initial power deliveries. (LA) (PG&E)
Right to be present	Notify prior to start-up and testing. (Goodland)

Except in emergency, reasonable prior notice required (of curtailment, interruption or reduction) (PG&E)

UTILITY	CUSTOMER
	Facility must always notify of outage. (PG&E)

J. Land Rights

UTILITY	CUSTOMER
Right to inspect, repair or remove.	Provide without cost, location and right-of-way for access — for necessary company apparatus. (Goodland) (Texas)
	Supply right-of-way free of cost Furnish access for utility employees free of charges when on utility business (Plains)
Procure land rights necessary for necessary facilities installed on land other than that of customer. Customer bears cost and final responsibility to procure.	Grant to utility all necessary right of way easements for term of agreement and execute documents required to record. Bear cost and share responsibility of procuring such land rights if use of land owned by other than parties is required. (PG&E)

K. Regulatory Approvals

UTILITY	CUSTOMER
Duty to purchase conditioned on obtaining necessary approvals (detailed) at reasonable cost.	Duty to aid in procurement of approvals (Plains)

Sample Provision

The duty of the Cooperative to provide service to Producer and of Plains to receive service from Producer is conditioned upon secur-

UTILITY		CUSTOMER
	ing and retaining the necessary approvals, franchises, rights-of-way and permits, at costs in their judgments reasonable and without expropriation, and the Producer agrees to furnish right-of-way over land which is owned, leased or controlled by the Producer, to the extent of his, her or its rights therein, free of cost, and to aid in every way in securing other necessary approvals, franchises, right-of-way and permits, and to furnish the Cooperative's and Plains' employees, agents and contractors access to Producer's premises free of tolls or other charges when employee, agents or contractors are on the Cooperative's Plains' business.	

L. Codes and Standards

UTILITY		CUSTOMER
	All equipment shall meet standards of good utility practice and be capable of continuous parallel operation. (TVA)	
		Meet all applicable codes and all standards of Prudent Electrical Practice (LA) (PG&E) Equipment must meet the requirements of state electric inspection and other public authorities before connection with utility. (PG&E)

M. Removal of Equipment

UTILITY	CUSTOMER
Utility has right to remove facilities within reasonable time after expiration of agreement (Plains)	

IX. OPERATIONS

A. Date of operation and/or Initial Service

1. Date specified — "The scheduled operation date of the seller's facility is ____________________." (PG&E)
2. Date of initial service is relative, e.g., commencement of billing period immediately following approval of agreement and written verification that facilities described are ready for service. (Plains)

END

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